Control Number: 49737

Item Number: 254

Addendum StartPage: 0

RECEIVED

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

2020 FEB 12 PM 2:52

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR CERTIFICATE OF CONVENIENCE AND NECESSITY AUTHORIZATION AND RELATED RELIEF FOR THE ACQUISITION OF WIND GENERATION FACILITIES	§ § § § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

FILING CLERK

REBUTTAL TESTIMONY

FEBRUARY 12, 2020

TABLE OF CONTENTS

File provided electronically on the PUC Interchange

AARON
AEP Witness Aaron SWEPCO TX Rebuttal_Tax Benefit Table xlsx
Brice
19-035-U_80_2 Settlement Agreement pdf
Attachment 3 (PSO WFA Rider_Clean) pdf
Attachment 4 (PSO FCA Rider_Clean) pdf
Attachment 5 (PSO Green Energy Choice Tariff_Clean) pdf
Attachment A pdf
PUD 201900048 Draft Order Adopting Joint Settlement 1 22 20 afternoon OAG Edits (002) pdf
ERRATA2020-02-03-135341 pdf
PFEIFENBERGER
Pfeifenberger WP-R-1 - Figure 1 xlsx
Pfeifenberger WP-R-2 - Figures 2 and 4 xlsx
Pfeifenberger WP-R-3 - Figure 5 xlsx

Commission Order ER19-105 (support for Merchant Gas Gen WACC) pdf
LBNL Study_wind_and_solar_impacts_on_wholesale_prices_approved pdf
2012 annual state of the market report pdf
2013 annual state of the market report pdf
2014 annual state of the market report pdf
2015 annual state of the market report pdf
2016 annual state of the market report pdf
2017 annual state of the market report pdf
2018 annual state of the market report pdf
2019 Property Value Study (Texas Comptroller Report) pdf

BLETZACKER
Air Liquide pdf
Bletzacker WP Non-Confidential xlsx
Eastman pdf
Komatsu pdf
occidental pdf
Putting-a-price-on-carbon-CDP-Report-2017 pdf
TORPEY
46936 order pdf
46936 pollock settlement testimony pdf
Copy of JSA-7.xlsx
SPS Docket 46936 (Adelman Exhibits_for WACC)_Copy of JSA-2 xlsx
SPS Docket 46936 (AdelmanTXDirect) doc
Torpey WorkPapers xlsx

354

SOAH DOCKET NO. 473-19-6862

PUC DOCKET NO. 49737

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

REBUTTAL TESTIMONY OF

THOMAS P. BRICE

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

FEBRUARY 12, 2020

TESTIMONY INDEX

EXHIBITS

EXHIBITS	DESCRIPTION
EXHIBIT TPB-1R	SWEPCO's Supplemental response to TIEC 2-2

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Thomas P. Brice. My business position is Vice President Regulatory and Finance for Southwestern Electric Power Company (SWEPCO or the Company). My business address is 428 Travis Street, Shreveport, Louisiana 71101.

Q. ARE YOU THE SAME THOMAS P. BRICE WHO FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to portions of the testimonies of Mr. Jeffrey Pollock and Mr. Charles S. Griffey on behalf of Texas Industrial Energy Consumers (TIEC), Mr. Scott Norwood on behalf of Cites Advocating Reasonable Deregulation (CARD), Mr. James W. Daniel on behalf of East Texas Electric Cooperative Inc. (ETEC) and Northeast Texas Electric Cooperative, Inc. (NTEC), Ms. Ruth Stark on behalf of the Staff of the Public Utility Commission of Texas (Staff), and Mr. Karl J. Nalepa on behalf of the Office of Public Utility Counsel (OPUC).

My rebuttal testimony will address the commitments SWEPCO has made in other jurisdictions regarding the Selected Wind Facilities and also how SWEPCO designed the guarantees that are being offered with the Selected Wind Facilities to ensure that customers will benefit from those facilities even under unexpected circumstances. As I discuss further below, customers are not well served by focusing only on unlikely scenarios, including very low production levels or sustained very low natural gas and energy prices. The risk that customers might not benefit from the Selected Wind Facilities because of an extended period of very low natural gas and energy prices is far outweighed by the risk to customers of doing nothing. The production tax credit benefits of $750 million in nominal dollars would be lost.

III. COMMITMENTS MADE IN OTHER JURISDICTIONS

Q. HAS SWEPCO OR PUBLIC SERVICE COMPANY OF OKLAHOMA (PSO) MADE ANY COMMITMENTS IN OTHER JURISDICTIONS REGARDING THE SELECTED WIND FACILITIES?

A. Yes. As of the time of the filing of this testimony, PSO has filed an unopposed settlement with the Oklahoma Corporation Commission (OCC), and that settlement has been recommended for OCC approval by the Administrative Law Judge. In addition, SWEPCO has filed a motion to approve a unanimous settlement with the Arkansas Public Service Commission. I have included these two settlements in the workpapers to this testimony. In those settlements, the two Companies have made certain commitments around the Capital Cost Cap, Minimum Production Guarantee, Production Tax Credit Guarantee, and a Most Favored Nations clause. The commitments made by PSO in the settlement before the OCC are addressed in the testimony of OPUC witness Mr. Nalepa. I will discuss some of the commitments made by PSO and SWEPCO in those two settlements later in this testimony.

Q. IF THESE TWO SETTLEMENTS ARE ADOPTED BY THE RESPECTIVE REGULATORY COMMISSIONS, IS THERE AN IMPORTANT IMPLICATION FOR SWEPCO'S REQUEST IN THIS CASE?

A. Yes. As I discuss in my direct testimony, the acquisition of the Selected Wind Facilities is designed to be scalable in the event that less than all four regulatory authorities grant the relief being requested of them. If the settlements filed with the Oklahoma and Arkansas commissions are approved, PSO and SWEPCO will have sufficient regulatory authority to meet the minimum purchase provisions contained in the applicable Purchase and Sales Agreements and proceed with the acquisition of at least a portion of the Selected Wind Facilities. SWEPCO continues to desire that its Texas customers also take advantage of the expected benefits offered by acquisition of the Selected Wind Facilities. However, SWEPCO realizes that Commission approval of the acquisition is necessary for Texas customers to take advantage of that opportunity.

IV. CUSTOMER BENEFIT CALCULATIONS

Q. THROUGHOUT HIS TESTIMONY, TIEC WITNESS MR. POLLOCK ADDRESSES THE EXPECTED CUSTOMER BENEFITS OF THE SELECTED WIND FACILITIES ASSUMING ENERGY OUTPUT AT THE P95 LEVEL. IS THE EXPECTED ENERGY OUTPUT OF THE SELECTED WIND FACILITIES AN IMPORTANT COMPONENT OF THE CUSTOMER BENEFIT CALCULATION?

A. Yes. More than any other factor, the expected energy output of the Selected Wind Facilities contributes to the benefits that customers will receive.

Q. HOW WAS THE EXPECTED ENERGY OUTPUT OF THE SELECTED WIND FACILITIES DETERMINED?

A. As discussed in the direct testimony of Company witness Mr. Jay Godfrey, as required by the terms of the Request for Proposals (RFP), each developer was required to submit a study prepared by an independent consultant of the expected energy output from the facility being bid into the RFP. In addition, the developers were required to provide supporting site information including raw meteorological data to the Company for review by the Company's independent wind consultant. The Company's independent wind consultant was Simon Wind Inc. (Simon Wind), an experienced consulting firm, that was hired to (1) independently review wind resource assessments and the expected energy output included in each of the RFP proposals; and (2) develop a wind energy resource assessment for each of the Selected Wind Facilities.

Q. HOW WERE THESE INDEPENDENT WIND STUDIES STRUCTURED?

A. The reports were structured to show the expected production from the facility (a 50% probability that production would exceed that amount and a 50% probability that production will be less than that amount), which is designated as the "P50" case. The reports contained other production levels, including a P95 case (a 95% probability that production will exceed that amount and a 5% probability that production will be less). Because the P50 case represents the production expected from the Wind Facilities, many of SWEPCO's customer benefits calculations provided in its direct case were based on the P50 scenario. However, to produce a robust set of customer benefit sensitivities, SWEPCO also calculated customer benefits at a P95 level. As shown in Exhibit JFT-3 (errata) to the direct testimony of John Torpey, the expected level of customer benefits even under the P95 level is $1.366 billion (nominal) and $330 million (net present value).

Q. HAS ANY PARTY CHALLENGED THE VALIDITY OR CONCLUSIONS OF THE INDEPENDENT WIND REPORTS USED BY THE COMPANY IN THE CUSTOMER BENEFITS CALCULATIONS?

A. No. This is certainly important and relevant, as these studies confirm the expected output for the Selected Wind Facilities for the P50 (expected) scenario.

Q. DO THE CUSTOMER BENEFIT CALCULATIONS IN TIEC WITNESS MR. POLLOCK'S TESTIMONY CONSIST ALMOST ENTIRELY OF P95 SCENARIOS?

A. Yes. Without explanation, Mr. Pollock's testimony focuses on the P95 energy production scenario to the exclusion of other, more probable energy production scenarios such as the P50. Mr. Pollock's testimony addresses some of the assumptions made in the customer benefit calculations, such as the Locational Marginal Prices (as influenced by expected natural gas prices) and the possibility of some carbon emissions burden, which are open to debate. However, Mr. Pollock's testimony addresses these uncertainties through the lens of the P95 energy production case. Mr. Pollock does not challenge the validity of the independent wind studies or give any reason why the Selected Wind Facilities should be evaluated only under the P95 scenario rather than the probable P50 scenario. The question being addressed in this proceeding is whether customers are expected to benefit from the acquisition of the Selected Wind Facilities. To evaluate that question almost exclusively from the perspective of a very unlikely scenario is a disservice to customers.

Q. WILL YOU PLEASE PUT THE P95 SCENARIO IN PERSPECTIVE?

A. The P95 scenario, as addressed in Mr. Torpey's errata Exhibit JFT-3 and in Mr. Pollock's testimony, has a 5% chance of occurring over any five-year block of time and an even smaller chance of occurring over six consecutive five-year blocks. Yet, this is exactly what Mr. Pollock assumes in his analyses. It is not a reasonable or fair way to evaluate the expected benefits to customers of the acquisition of the Selected Wind Facilities on this basis.

Alternatively, the P5 capacity factor (*i.e.*, a very high level of energy production) is just as likely as the P95 outcome Mr. Pollock uses throughout his testimony. The P5 capacity factor is 49%, which would result in 28% more energy production and Production Tax Credits (PTCs) than a P95 outcome, significantly increasing customer benefits. Company witness Mr. Torpey further addresses this fact in his rebuttal testimony.

Q. PLEASE EXPLAIN WHY THE COMPANY SET THE GUARANTEE AT THE P95 LEVEL.

A. The guarantees were designed to ensure that customers would still receive benefits even if gas and power prices remained low, the actual capital cost reached the cost cap, and production remained at the unexpected low range of the wind studies. In fact, as shown on the attached EXHIBIT TPB-1R (SWEPCO's supplemental response to TIEC RFI 2-2), if the Selected Wind Facilities performed only at the P95 level for the entire 30-year study period and gas and power prices remained very low over that same period (Low Gas/No CO2), customers could still expect benefits of $473 million (nominal) and $43 million (net present value).

Q. ON PAGE 8 OF HIS TESTIMONY, OPUC WITNESS MR. NALEPA ALLEGES THAT THE BENEFITS OF THE SELECTED WIND FACILITIES ARE "VERY UNCERTAIN" AND THAT SWEPCO IS "PLACING ALL RISK ON ITS RATEPAYERS." IS THAT AN ACCURATE CHARACTERIZATION OF SWEPCO'S PROPOSAL?

A. No. The calculation of the benefits customers will receive from the Selected Wind Facilities, as a matter of necessity, must be based on estimates of future conditions. This is true of all system planning analyses. In this respect, the calculation of customer benefits associated with the Selected Wind Facilities is no different from those associated with any other proposed generation facility. That the calculation of benefits must be based on estimates of future conditions does not, in itself, make those expected benefits "very uncertain." Instead, the evaluation of the Selected Wind Facilities and any other proposed generation facility should be evaluated under a reasonable range of assumptions. That is exactly what the Company has done in this case. As discussed in the testimony of Company witness Mr. Torpey, the Selected Wind Facilities are expected to provide substantial benefits to customers under a variety of future conditions, including facility production far below the level reasonably expected, energy prices lower than those expected, and congestion costs high enough to justify construction of a gen tie. While the exact level of customer benefits that will be achieved over the next 30 years cannot be known at this time, it is not accurate to say that customer benefits associated with the Selected Wind Facilities are very uncertain. The benefits are no more uncertain than those associated with other system planning routinely conducted and relied on by utilities and regional transmission organizations (RTOs).

Likewise, Mr. Nalepa's allegation that SWEPCO is "placing all risk on its ratepayers" does not withstand scrutiny. Through its suite of guarantees offered in this proceeding, SWEPCO shoulders the risk that the facilities will cost more than expected (Capital Cost Cap Guarantee), may not qualify for the expected amounts of PTCs (the Production Tax Credit Eligibility Guarantee), and may produce less energy than the Minimum Production Guarantee. Still, to the extent that the facilities produce more energy than expected, that benefit will go to customers. In addition, the Company and customers will not carry the financing burden of the Selected Wind Facilities, as the Company is not obligated for any payments under the Purchase and Sale Agreements unless the actual purchase occurs consistent with the terms of the agreements. The Company is proposing to invest more than a billion dollars of its capital in the Selected Wind Facilities to provide long-term energy cost savings to SWEPCO customers. It is not accurate or fair to allege that SWEPCO is placing all risks on customers.

Q. WILL YOU PLEASE FURTHER ADDRESS THE RISK TO CUSTOMERS OF AN EXTENDED PERIOD OF EXTREMELY LOW ENERGY PRICES?

A. Intervenor witnesses Messrs. Pollock and Nalepa focus on a risk that natural gas prices and, by extension, energy prices will be so low for such a long time that customers will not benefit from acquisition of the Selected Wind Facilities. This is an unlikely scenario. As discussed in the direct testimony of Company witness Mr. Torpey, the Selected Wind Facilities are expected to provide $236 million (net present value) of customer benefit in the Low Gas No Carbon Burden sensitivity. The risk that customers might not benefit from the Selected Wind Facilities during an extended period of very low energy prices is far outweighed by the risk customers will face if SWEPCO does nothing (loss of PTCs). While the price of natural gas may stay relatively low for some period of time, the Selected Wind Facilities will incur no fuel cost at all. The customer benefit calculations shown in Mr. Torpey's testimony also quantify the risk of higher energy prices borne by customers if SWEPCO does not acquire the Selected Wind Facilities. If natural gas and energy prices track those in the Low Gas No Carbon Burden sensitivity, customers will pay $236 million more (NPV) for electricity over the next 30 years than they would pay if SWEPCO acquires the Selected Wind Facilities. The risk borne by customers increases to $396 million (NPV) in the Base Gas No Carbon Burden sensitivity and $718 million (NPV) in the High Gas with Carbon Burden sensitivity. When the full spectrum of natural gas and energy price scenarios are considered, it is clear that the acquisition of the Selected Wind Facilities will reduce risk for customers, not increase risk.

Q. ARE THERE PROBLEMS WITH MR. POLLOCK'S ASSUMPTION THAT EXTREMELY LOW ENERGY PRICES WILL PREVAIL FOR THE NEXT THIRTY YEARS?

A. Yes. Mr. Pollock fails to address a number of reasons why market prices could be higher than the low prices he projects, particularly if one were to assume future natural gas prices would be below even the Company's Low Gas/No CO2 sensitivity. First, renewable generation additions would slow down relative to current projections if future natural gas prices and associated power prices were to be as low as Mr. Pollock suggests. Thus, Mr. Pollock's assumption that extremely low gas prices will prevail for the next 30 years is inconsistent with his assumption that a lot more renewable power projects will get developed than those projected in the Southwest Power Pool (SPP) PROMOD reference case. Second, at Mr. Pollock's very low projected natural gas prices, more SPP coal generation would be retired than currently projected. Third, Mr. Pollock ignores that SPP's low current power prices are caused in part by a significant surplus of generation in the SPP footprint. As this surplus is reduced over time, SPP market prices will adjust accordingly. All three of these factors could increase wholesale power prices in SPP relative to those assumed in Mr. Pollock's testimony, which would increase the net customer benefit of the Company's Selected Wind Facilities. These factors are discussed further in the rebuttal testimony of Company witness Mr. Johannes Pfeifenberger.

Q. ON PAGE 54 OF HIS TESTIMONY, TIEC WITNESS MR. GRIFFEY ALLEGES THAT CUSTOMER BENEFITS ARE A FUNCTION OF NATURAL GAS PRICES AND ENERGY MARKET PRICES. IS THAT A COMPLETE DESCRIPTION OF WHAT DRIVES CUSTOMER BENEFITS IN THIS CASE?

A. No. Certainly, the value of the energy produced by the Selected Wind Facilities is an important factor to consider when evaluating the Selected Wind Facilities and one that will fluctuate with the prevailing price of energy. However, Mr. Griffey's assessment ignores the very significant value provided by the PTCs. As noted above, PTCs are earned when the Selected Wind Facilities produce energy. That production is driven by the wind. And, as noted above, no party has questioned the validity of the independent wind reports relied on in the customer benefit calculations. The value of a PTC is not in dispute since it is determined by law. The expected value of the PTCs to be generated by the Selected Wind Facilities over the first ten years of operation is approximately $750 million net of deferred tax asset (DTA) carrying costs. SWEPCO has guaranteed that the Selected Wind Facilities will qualify for PTCs. And, the value of the PTCs earned does not fluctuate with natural gas or energy prices.

Q. ON THIS SAME PAGE OF HIS TESTIMONY, MR. GRIFFEY ALLEGES THAT THE DECISION TO ACQUIRE WIND ENERGY FOR ECONOMIC ENERGY SAVINGS DOES NOT HAVE TO BE MADE AT THIS TIME. DO YOU AGREE?

A. No. Under current law, the PTCs available to new wind generation are being phased out. Given that the PTCs are one of the largest components of expected customer benefits, the decision of whether to take advantage of those PTCs on behalf of customers should be made at this time. On page 55 of his testimony, Mr. Griffey alleges that, if natural gas prices significantly increase in the future, SWEPCO will still have the ability to procure renewable power. Mr. Griffey's recommended path is fraught with risk for customers. If SWEPCO were to acquire wind facilities in the future, under current law, they would qualify for less PTCs than those that will be earned by the Selected Wind Facilities or no PTCs at all. If Mr. Griffey is suggesting that SWEPCO could enter into Purchased Power Agreements (PPAs) with wind facilities after natural gas prices significantly increase, the pricing of those PPAs would undoubtedly be influenced by the increase in energy market prices driven by the higher natural gas prices. Given that the Selected Wind Facilities are expected to provide customers benefit under a wide range of assumptions, Mr. Griffey's "wait and see" path is the more risky path for customers. There is no basis to assume that the Company could replicate the benefits of the proposed projects in the future.

Q. ON PAGE 40 OF HIS TESTIMONY, MR. GRIFFEY OBSERVED THAT FEDERAL LEGISLATION RECENTLY EXTENDED THE PTC FOR ANOTHER YEAR AT THE 60% LEVEL. DOES THAT CHANGE THE RISK OF DOING NOTHING?

A. Not significantly, in my opinion. The Traverse and Maverick facilities will qualify for the 80% level of PTCs and the Sundance facility will qualify for the 100% level of PTCs. That level of PTCs will not be available to new facilities in the future. And, while the 60% level of PTCs has been extended for an additional year for projects starting construction in 2020, all PTCs will be phased out after that year. When seeking to lock in benefits on behalf of customers, this fact cannot be ignored.

Q. ON PAGE 48 OF HIS TESTIMONY, MR. GRIFFEY ALLEGES THAT SWEPCO CHOSE THE PATH THAT WOULD ALLOW IT TO BUILD RATE BASE AND EARN A RETURN. IS THAT A COMPLETE AND FAIR CHARACTERIZATION OF SWEPCO'S MOTIVATION FOR ACQUIRING THE SELECTED WIND FACILITIES?

A. No. SWEPCO is proposing to make a significant investment of capital on behalf of customers in order to achieve long-term energy savings for SWEPCO customers. While SWEPCO should have the opportunity to recover its costs and a reasonable return on that investment, like any other investment prudently made to provide service to customers, SWEPCO's investment in the Selected Wind Facilities also facilitates the guarantees being offered to customers. SWEPCO is offering a Capital Cost Cap, yet if the Selected Wind Facilities were to cost less than expected, that benefit will be passed on to customers. SWEPCO is offering a Minimum Production Guarantee, yet if production exceeds that expected, all of that benefit will be passed on to customers.

SWEPCO is offering a Production Tax Credit Guarantee and to credit customers directly with those PTCs earned by the Selected Wind Facilities. Ownership of the Selected Wind Facilities will facilitate the offering of these guarantees. It is not common for these risks to be absorbed by the utility, while only having the opportunity to earn a regulated or cost of service rate of return.

SWEPCO currently owns no renewable generation facilities. Ownership of the Selected Wind Facilities will further diversify the Company's generation portfolio and, at the same time, address customer interest in more renewable energy to meet their sustainability and renewable energy goals.

V. MINIMUM PRODUCTION GUARANTEE

Q. OPUC WITNESS MR. NALEPA URGES THE COMMISSION TO CONDITION THE ACQUISITION OF THE SELECTED WIND FACILITIES ON SWEPCO GUARANTEEING A P50 PRODUCTION LEVEL. WOULD SUCH A REQUIREMENT BE REASONABLE?

A. No. The purpose of the Minimum Production Guarantee is to help ensure customers benefit from the Selected Wind Facilities even if production levels are far less than expected, not to penalize the Company if production deviates from the expected level. The Company's proposed Minimum Production Guarantee ensures customer benefits even if the Selected Wind Facilities, over each five-year time period for the first ten years, performs below the P95 Net Capacity Factor, which is lower than the expected net capacity factor (P50). Even if the Selected Wind Facilities operated at the P95 guaranteed levels assuming the base gas fundamentals price forecast, with and without an assumed carbon burden, the customer benefits would be $1,470 million ($350 million NPV) and $964 million ($199 million NPV), respectively. Therefore, the Minimum Production Guarantee, as proposed by the Company, achieves the purpose of helping to ensure customers benefit even if production levels are far less than expected.

Mr. Nalepa's recommendation is not reasonable because it penalizes the Company for any deviation below average expected production. It is the equivalent of asking the Company to guarantee the average rainfall, or the average temperature in a given season. It is an unbalanced proposal under which customers would receive all the benefits of above-average production while the Company would bear all the risk of below-average production. It is simply not reasonable.

Mr. Nalepa's proposal also ignores that the Company has offered a suite of guarantees designed to ensure customer benefits even under unexpected circumstances, including the cost cap, PTC eligibility guarantee, and the minimum production guarantee.

Q. ON PAGE 30 OF HIS TESTIMONY, OPUC WITNESS MR. NALEPA STATES THAT, IN OKLAHOMA, IN THE CONTEXT OF ITS SETTLEMENT, PSO HAS COMMITTED TO EXTEND ITS P95 MINIMUM PRODUCTION GUARANTEE WITH THE 30-YEAR LIFE OF THE SELECTED WIND FACILITIES. IS THAT TRUE?

A. Yes. SWEPCO has made this same commitment within the context of its Arkansas settlement. Also, PSO and SWEPCO have provided this guarantee within the context of their respective settlements with no exception for force majeure. And, in the context of the Arkansas settlement, SWEPCO has provided this guarantee with no exception for economic curtailments of the Selected Wind Facilities by the Southwest Power Pool (SPP). While these expansions of the Minimum Production Guarantee were agreed to within the context of comprehensive settlements, SWEPCO would entertain these expansions to the Minimum Production Guarantee offered in Texas either in a comprehensive settlement entered in this case or as part of a reasonable suite of conditions contained in a final order approving the acquisition of the Selected Wind Facilities.

VI. PTC GUARANTEE

Q. OPUC WITNESS MR. NALEPA RECOMMENDS THAT THE COMMISSION CONDITION THE ACQUISITION OF THE SELECTED WIND FACILITIES ON SWEPCO GUARANTEEING THE EXPECTED LEVEL OF PTCS WHETHER OR NOT SWEPCO QUALIFIES FOR THE PTCS. IS SWEPCO WILLING TO PROVIDE SUCH A GUARANTEE?

A. Yes. That guarantee is contained in my direct testimony. However, it is important to note the single exception to that guarantee reflected in my direct testimony – an exception for changes in federal law pertaining to PTCs, including changes to the Internal Revenue Code. Historically, tax law changes have been prospective in nature, rather than retroactively removing a benefit that has been provided to and relied on by taxpayers. This is a point that was made by TIEC in the evaluation of the acquisition of wind facilities by Southwestern Public Service Company (SPS) in Docket No. 46936:

> As to the risk that Congress would reduce or eliminate PTCs for plants that have already been built, TIEC agrees with SPS witness David Hudson that that is extremely unlikely. Congress has never retroactively reduced the level of PTCs, and even in the recent House legislation that would have reduced the value of PTCs by eliminating the inflation adjustment, projects for which construction began prior to the enactment of the legislation – such as SPS's Wind Plants – were exempt.

(TIEC Response to Commissioner Questions, April 19, 2018.) Under the PTC guarantee made by SWEPCO in this case, SWEPCO bears the risk that the Selected Wind Facilities will not qualify for the PTCs at the expected levels. However, the Company cannot guarantee what Congress may or may not do in the future.

VII. ADDITIONAL GUARANTEES PROPOSED BY INTERVENOR WITNESSES

Q. OPUC WITNESS MR. NALEPA URGES THE COMMISSION TO CONDITION THE ACQUISITION OF THE SELECTED WIND FACILITIES ON SWEPCO GUARANTEEING ENERGY COST SAVINGS BASED ON THE COMPANY'S FUNDAMENTALS BASE CASE FORECAST OF NATURAL GAS PRICES. WOULD THAT BE REASONABLE?

A. No. The Company's analysis of the Selected Wind Facilities shows that they are expected to provide substantial customer benefits under a wide variety of assumptions, including under a variety of potential natural gas prices. The purpose of the guarantees being offered by SWEPCO is to help ensure that customers still benefit from the Selected Wind Facilities even under unexpected circumstances. The guarantees are not designed to be a penalty for SWEPCO if circumstances deviate from those expected.

Fuel costs, and in particular natural gas costs, have historically been volatile, particularly over extended periods like the 30-year expected life of the Selected Wind Facilities. Mr. Nalepa's proposal that the Company assume such a risk is extraordinary and, to my knowledge, unprecedented. It would mark a fundamental shift in utility ratemaking and could be inconsistent with governing law that requires the Commission to provide utilities an opportunity to recover their expenses and a reasonable return on their investment. SWEPCO's approved return on equity does not begin to compensate it for such a huge increase in risk. Moreover, as explained in the testimonies of Messrs. Karl Bletzacker and Torpey, the Company has appropriately tested the economics of the Selected Wind Facilities across a reasonable range of natural gas prices likely to prevail over the facilities' expected life. Mr. Nalepa's recommendation amounts to a penalty for SWEPCO if natural gas prices are lower than those expected, while reserving to customers all of the benefit if natural gas prices are higher than expected.

Q. ON PAGE 13 OF HIS TESTIMONY, TIEC WITNESS MR. POLLOCK OBSERVES THAT SWEPCO'S COST CAP GUARANTEE DOES NOT ENCOMPASS ONGOING CAPITAL ADDITIONS. DO YOU HAVE A COMMENT?

A. Yes. This observation is addressed by Company witness Mr. Joseph DeRuntz. However, from a ratemaking point of view, capping the prudent capital additions that will be made by SWEPCO over the life of the Selected Wind Facilities is not necessary or reasonable. Future capital additions will be subject to a prudence review in future Commission proceedings.

VIII. DEFERRED TAX ASSET

Q. ON PAGE 33 OF HIS TESTIMONY MR. POLLOCK DESCRIBES THE DEFERRED TAX ASSET AS A "LENDING SCHEME." IS THAT AN ACCURATE DESCRIPTION OF THE DEFERRED TAX ASSET THAT MAY BE CREATED BY THE PRODUCTION TAX CREDITS EARNED BY THE SELECTED WIND FACILITIES?

A. No. SWEPCO's request to include any deferred tax asset associated with the Selected Wind Facilities in rate base is consistent with standard ratemaking. Deferred tax assets are consistently included in rate base. For example, in SWEPCO's most recent base rate proceeding, Docket No. 46449, the Commission included several deferred tax assets in rate base (see filing package Schedule G-7.4, Account No. 190).

Q. WHY WOULD IT BE INEQUITABLE FOR THE COMPANY TO BE DENIED A CARRYING COST ON THE DEFERRED TAX ASSET?

A. The Company is providing customers a benefit by reducing the revenue requirement of the Selected Wind Facilities as Production Tax Credits are generated, not as they are utilized. This can result in a timing difference where the Company has provided this benefit to customers before the Company has been able to apply this benefit on its tax return. When a PTC is not used by the Company on its tax return in the year in which it is earned, a deferred tax asset is created for the PTCs the Company will ultimately include on its tax return in a future year. When this occurs, the Company should be compensated for its investment in this asset just as it is compensated for its investment in any other asset, including other deferred tax assets, included on the Company's balance sheet, requiring financing.

The Company is putting its balance sheet at risk to finance the Selected Wind Facilities, with the use of both debt and equity, to provide SWEPCO customers with more affordable renewable energy. The Company has stated in its initial filing that our intent is to reduce the revenue requirement of the Selected Wind Facilities, dollar for dollar, with the amount of the Production Tax Credits (grossed up for taxes), as generated. This means that there is no lag to the customer for the benefit of the Production Tax Credits generated; 100 percent of the benefits flow directly to the customer. This is, in essence, providing the customer a discount that is made available by the Company's investment in the Selected Wind Facilities, like any other regulated capital investment the Company makes. And, like any other regulated investment made by the Company that provides benefits to the customers and is prudent, the utility should be allowed to earn a fair and reasonable return on its rate base, of which deferred assets are a part. Further, the Company modeled the expected cost of a DTA in its customer benefits calculations, all of which show net benefits to customers. Mr. Pollock is essentially asking for all the benefits of the proposed acquisition without including all of the costs that make those benefits possible. Company Witness John Aaron also explains the reasonableness of the Company's collection of carrying charges on the DTA.

Q. MR. POLLOCK ALLEGES THAT THE CREATION AND INCLUSION IN RATE BASE OF A DTA IS "NOT A PROPER BUSINESS ACTIVITY FOR A REGULATED UTILITY." DO YOU AGREE?

A. No. As discussed extensively in the Company's direct testimony and petition, a very significant part of the customer value provided by acquisition of the Selected Wind

Facilities is the earning and crediting to customers of the Production Tax Credits. SWEPCO will be earning those PTCs by the investment of more than $1 billion of its capital in the Selected Wind Facilities. That the Company may not be able to use all PTCs in the year in which they are earned does not change this basic fact.

Q. ARE THERE OTHER TAX CONSIDERATIONS THAT CONTRIBUTE TO THE OCCURRENCE OF A DTA?

A. Yes. The Selected Wind Facilities will qualify for accelerated depreciation under the Internal Revenue Code. That accelerated depreciation will lower the Company's net income in the early years of the acquisition and, therefore, limit the Company's ability to use the PTCs during that time. However, this accelerated depreciation benefits customers in the form of a reduced rate base on which the Company will earn a return. This accelerated depreciation benefit was included in the calculation of expected customer benefits. Mr. Pollock wants customers to receive the benefit of the accelerated depreciation without having to pay for the related DTA. Company witness Mr. Aaron further addresses this fact in his rebuttal testimony.

Q. STAFF WITNESS MS. STARK RECOMMENDS THAT THE COMMISSION NOT PROVIDE PRE-APPROVAL OF THE INCLUSION OF A DTA IN SWEPCO'S RATE BASE. DO YOU HAVE A COMMENT?

A. Yes. It is important to note that Ms. Stark's recommendation is limited to the question of what she terms as an "open-ended pre-approval of the ratemaking treatment for the deferred tax asset." Ms. Stark does not state that inclusion of a DTA in rate base would be in any way improper. In her testimony, Ms. Stark acknowledges the Company's position that the inclusion of a DTA in rate base would be standard ratemaking that is no different from that afforded other components of accumulated deferred income taxes. Ms. Stark does not dispute this fact. Instead, she cites this position as one reason that pre-approval is not necessary.

Q. MS. STARK EXPRESSES CONCERN THAT DTA AMOUNTS AND ASSOCIATED CARRYING COSTS ARE NOT CURRENTLY KNOWN (PAGE 7-10). IS THE COMPANY PROPOSING THAT THESE AMOUNTS BE DETERMINED IN THIS CASE?

A. No. Those amounts will be determined in a future rate proceeding as PTCs are earned and deducted from the Company's taxes.

IX. OFF SYSTEM SALES

Q. ON PAGE 52 OF HIS TESTIMONY, TIEC WITNESS MR. GRIFFEY ALLEGES THAT, "UNDER THE SPP CONSTRUCT, SWEPCO NEEDS NO INCENTIVE TO OFFER ITS PLANTS INTO THE MARKET AND SHOULD NOT EARN 10% OF THE SAVINGS." DO YOU AGREE WITH MR. GRIFFEY?

A. No. Pursuant to Commission Substantive Rule 16 TAC 25.236(a) (9), the Commission has consistently allowed SWEPCO to retain 10% of its off-system sales. Further, if Mr. Griffey is implying that the Company does not engage in significant activities to achieve these off-system sales margins, he is mistaken. The scope and objective of the SPP Integrated Marketplace is limited to determining the least-cost solution to meet the system reliability needs, the energy needs and the reserve requirements needed for the next operating day.

SWEPCO's optimization activities extend over a much longer timeframe. For example, during a low demand period, such as those often occurring over the weekends, the variable cost of operating a unit may exceed the market clearing price for the next operating day as calculated by SPP's economic dispatch model. In other words, in the Day-Ahead market, this unit will not be selected to run by SPP and would instead shut down. However, as one extends the timeframe under which the unit's economic operation in relation to the market is evaluated, then the decision to run or shut down the unit over the weekend becomes much more complex. For example, to properly evaluate the unit economics requires information such as unit shut down and startup costs, forecasted demand not just for the next day but for many days in the future, corresponding forecasted Day-Ahead clearing prices, and potential performance issues for other units within SWEPCO's portfolio. This optimization process occurs outside the SPP IM responsibilities of SWEPCO as an SPP market participant, and relies on the combined expertise and coordination of the many groups within AEP for its success. These groups include Meteorology, Fuel Procurement, Generation, Trading, Bid Development, and LMP and Load Forecasting.

X. GENERATION TIE-LINE APPROVAL

Q. CITIES WITNESS MR. NORWOOD RECOMMENDS THAT SWEPCO BE REQUIRED TO SEEK COMMISSION APPROVAL FOR ANY NEW "TRANSMISSION LINES" THAT IT SEEKS TO CONSTRUCT TO MITIGATE CONGESTION COSTS ASSOCIATED WITH THE ENERGY SUPPLIED BY THE SELECTED WIND FACILITIES. DO YOU HAVE A COMMENT?

A. Yes. I interpret Mr. Norwood's suggestion to be applicable only to the building of an extended and dedicated generation tie-line to connect the Selected Wind Facilities directly to the AEP load zone in SPP. SWEPCO does not oppose such a suggestion. On the other hand, the build out of the transmission grid in the Southwest Power Pool is a matter entrusted to the policies and procedures of the Southwest Power Pool, as regulated by the Federal Energy Regulatory Commission. Construction of transmission in Oklahoma as part of the SPP integrated system is not typically within the Commission's purview. This fact is further discussed by SWEPCO rebuttal witness Mr. Ross.

XI. PURA § 14.101 APPLICABILITY AND FINDING

Q. ETEC WITNESS MR. DANIEL ALLEGES THAT THE COMMISSION MUST MAKE A PUBLIC INTEREST FINDING IN THIS CASE UNDER PURA § 14.101. DO YOU HAVE A COMMENT?

A. Yes. For the reasons stated in SWEPCO's application, the Company does not believe that § 14.101 applies to SWEPCO's request in this case. The Selected Wind Facilities will not be located in this state. Nonetheless, if the Commission were to find that Section of PURA to be applicable to SWEPCO's application in this proceeding, the evidentiary record demonstrates that the acquisition of the Selected Wind Facilities is in the public interest.

XII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' SECOND REQUEST FOR INFORMATION REQUEST FOR INFORMATION

Question No. TIEC 2-2:

Please provide an NPV evaluation of the guarantees case assuming Low Gas, No CO2.

Response No. TIEC 2-2:

The Company believes that the chance of the combination of the Low Gas, No CO2 guarantees (P95) case occurring over either the 10 year guarantee period or the 30 year analysis period is remote, which is why it wasn't prepared and included in the Company's filing. The P95 level of production assumed in this case only has a 5% chance of occurring over any 5 year block of time and an even smaller chance over six 5 year blocks of time in a row. Production is just as likely to occur at the P5 level as it is at the P95 level. The requested case would assume no CO2 legislation is enacted at any time between now and 2051, the extremely low power prices in the Low Gas, No CO2 case are sustained for the 10 year guarantee period and through 2051, and the P95 level of production occurs for expected periods of time. The average generation weighted around the clock power price in the first 5 years of this case is only $25.25 and the first 10 years is only $27.63. By comparison, day-ahead and real-time prices in SPP both averaged approximately $25/MWh for the year in 2018.

Source: SPP State of the Market Report:
https://www.spp.org/documents/59861/2018%20annual%20state%20of%20the%20market%20report.pdf

Notwithstanding these issues, for the purpose of responding to this request, the Company is preparing an estimate of what that case would look like by using simplifying assumptions and numbers from other cases which would be the same in this case. As stated in the Company's response to TIEC 1-19, the Company is reviewing a portion of its analysis which may lead to updated/supplemental new workpapers for Company witness Torpey's economic benefit analysis. Once this review is complete this response will be supplemented with the requested information.

Supplemental Response No. TIEC 2-2:

The Company believes that the chance of the combination of the Low Gas, No CO2 guarantees (P95) case occurring over either the 10 year guarantee period or the 30 year analysis period is remote, which is why it wasn't prepared and included in the Company's filing. The P95 level of production assumed in this case only has a 5% chance of occurring over any 5 year block of time and an even smaller chance over six 5 year blocks of time in a row. Production is just as likely to occur at the P5 level as it is at the P95 level. The requested case would assume no CO2 legislation is enacted at any time between now and 2051, the extremely low power prices in the Low Gas, No CO2 case are sustained for the 10 year guarantee period and through 2051, and the P95 level of production occurs for expected periods of time. The average generation weighted around the clock power price in the first 5 years of this case is only $25.25 and the first 10 years is only $27.63. By comparison, day-ahead and real-time prices in SPP both averaged approximately $25/MWh for the year in 2018.

Source: SPP State of the Market Report:
https://www.spp.org/documents/59861/2018%20annual%20state%20of%20the%20market%20report.pdf

Notwithstanding the remote likelihood of this case occurring, in response to this request the Company prepared the requested analysis. See TIEC_2_2_Supplemental_Attachment_1 for the requested analysis, along with the PLEXOS inputs supporting the production cost savings in this case. Capacity value, PTC, DTA carrying charges, and the wind facility revenue requirement are unchanged from the P95 cases initially presented in witness Torpey's Exhibit JFT-3.

Prepared By: Jon R. Maclean — Title: Resource Planning Mgr

Prepared By: James F. Martin — Title: Regulatory Case Mgr

Sponsored By: John F. Torpey — Title: Mng Dir Res Plnning&Op Anlysis

NORTH CENTRAL WIND ENERGY FACILITIES - SWEPCO 810 MW SHARE OF ALL THREE PROJECTS
P95 15% CAPACITY CREDIT LOW GAS NO CARBON CUSTOMER COSTS AND BENEFITS - No Tie Line
$ in Millions (Nominal unless otherwise indicated)

Year	NPV	Total 31 Yr. Nominal	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1 Production Cost Savings Excluding Congestion/Losses	$1,111	$3,486	$9	$65	$67	$70	$73	$76	$78	$81	$82	$85	$88
2 Congestion and Losses	($199)	($535)	($2)	($14)	($14)	($15)	($16)	($16)	($17)	($18)	($19)	($19)	($19)
3 Capacity Value	$29	$83	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Production Tax Credits, Grossed Up	$546	$834	$13	$76	$79	$79	$82	$82	$85	$85	$88	$88	$75
5 Deferred Tax Asset Carrying Charges	($96)	($163)	($0)	($3)	($8)	($12)	($14)	($16)	($17)	($18)	($19)	($19)	($18)
6 Wind Facility Revenue Requirement	($1,348)	($3,233)	($17)	($132)	($130)	($130)	($128)	($127)	($126)	($124)	($123)	($121)	($119)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$43**	**$473**	**$3**	**($7)**	**($6)**	**($7)**	**($2)**	**($1)**	**$3**	**$6**	**$11**	**$15**	**$8**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$92	$99	$103	$107	$109	$113	$110	$107	$119	$115	$119	$129	$133
2 Congestion and Losses	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)
3 Capacity Value	$0	($7)	($7)	($7)	($7)	($6)	$47	$55	($1)	$57	$56	($3)	($2)
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	($13)	($5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($116)	($114)	($112)	($110)	($108)	($106)	($104)	($102)	($100)	($98)	($97)	($95)	($93)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**($57)**	**($46)**	**($35)**	**($29)**	**($24)**	**($17)**	**$35**	**$42**	**($1)**	**$55**	**$60**	**$12**	**$19**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$140	$145	$189	$195	$200	$203	$185
2 Congestion and Losses	($19)	($19)	($19)	($19)	($19)	($19)	($16)
3 Capacity Value	($2)	($2)	$12	$11	($35)	($37)	($37)
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($91)	($89)	($88)	($86)	($85)	($86)	($81)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$29**	**$35**	**$95**	**$101**	**$61**	**$62**	**$52**

PSO - SWEPCO North Central Wind Energy Facilities
Inputs - TIEC 2-2 P95 Low NoCO2

Year	NPV	Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036

Allocation of Capacity to Jurisdictions.	Modeled Allocation	Total Project Percent	SWEPCO Percent
Arkansas	155	10 4546%	19 1668%
Louisiana	268	18 0740%	33 1356%
Texas	309	20 7888%	38 1128%
FERC	78	5 2289%	9 5863%
Total SWEPCO	810		100 00%
Oklahoma	675	45 45%	
Total Project	1,485	100 00%	

NPV Discount rate 7 09%

Off System Sales Margin Retained by AEP - Deduct from Plexos Benefits

Total Plexos OSS Margin by Case

Margin Retention	Margin Retained
Arkansas	10 0%
Louisiana	10 0%
Texas	10 0%
FERC	10 0%

TIEC 2-2 SWEPCO Low No CO2 P95 Case PLEXOS Inputs

Net Production Cost Savings	NPV	Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Project Low Gas No Carbon	$6,755	$17,478	$552 8	$525 0	$545 9	$541 9	$569 0	$579 3	$577 9	$570 2	$509 2	$482 5	$484 6	$481 3	$474 8	$460 8	$473 5	$481 1
Baseline Low Gas No Carbon=P50 15% case	$7,676	$20,465	$559 7	$576 5	$599 3	$597 4	$626 2	$639 1	$639 5	$633 2	$573 6	$549 8	$555 1	$555 5	$556 0	$546 1	$563 2	$573 4
Savings, pre-margin sharing pre Gen Tie	($921)	($2,987)	($6 9)	($51 5)	($53 3)	($55 5)	($57 2)	($59 9)	($61 6)	($63 0)	($64 3)	($67 2)	($70 5)	($74 2)	($81 1)	($85 3)	($89 7)	($92 3)
Less Lost energy value from losses on Gen Tie																		
Lost GWh on Gen Tie			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual Average market Price-Load Hub ($ MWh)			23 4	23 9	24 7	25 5	26 5	27 3	28 2	39 4	39 6	40 6	41 6	42 7	43 6	45 5	46 9	47 8
Lost Energy Revenue ($MM)			$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
Savings, pre-margin sharing	($921)	($2,987)	($6 9)	($51 5)	($53 3)	($55 5)	($57 2)	($59 9)	($61 6)	($63 0)	($64 3)	($67 2)	($70 5)	($74 2)	($81 1)	($85 3)	($89 7)	($92 3)

OSS Margin Savings

P95 Low Gas No Carbon Fundamentals ($ Millions)	NPV	Nominal Total 31 year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
SWEPCO Gross OSS Margin With Project	$357	$1,644	$3 57	$4 34	$5 27	$6 75	$2 68	$3 26	$4 67	$3 23	$8 13	$10 82	$15 00	$21 07	$19 35	$30 39	$34 44	$36 60
SWEPCO Gross OSS Margin Without Project	$264	$1,285	$3 12	$1 52	$1 97	$2 69	$0 92	$1 10	$1 51	$0 95	$3 38	$5 18	$7 48	$11 92	$10 89	$18 78	$21 91	$22 75
SWEPCO Gross OSS Margin Increase	$93	$359	$0 5	$2 8	$3 3	$4 1	$1 8	$2 2	$3 2	$2 3	$4 8	$5 6	$7 5	$9 1	$8 5	$11 6	$12 5	$13 8
Arkansas Margin Increase	$18	$69	$0 1	$0 5	$0 6	$0 8	$0 3	$0 4	$0 6	$0 4	$0 9	$1 1	$1 4	$1 8	$1 6	$2 2	$2 4	$2 7
La Margin Increase	$31	$119	$0 2	$0 9	$1 1	$1 3	$0 6	$0 7	$1 0	$0 8	$1 6	$1 9	$2 5	$3 0	$2 8	$3 8	$4 2	$4 6
Texas Margin Increase	$35	$137	$0 2	$1 1	$1 3	$1 5	$0 7	$0 8	$1 2	$0 9	$1 8	$2 1	$2 9	$3 5	$3 2	$4 4	$4 8	$5 3
FERC Margin Increase	$9	$34	$0 0	$0 3	$0 3	$0 4	$0 2	$0 2	$0 3	$0 2	$0 5	$0 5	$0 7	$0 9	$0 8	$1 1	$1 2	$1 3
Arkansas Retained Margin Increase	$2	$7	$0 0	$0 1	$0 1	$0 1	$0 0	$0 0	$0 1	$0 0	$0 1	$0 1	$0 1	$0 2	$0 2	$0 2	$0 2	$0 3
La Retained Margin Increase	$3	$12	$0 0	$0 1	$0 1	$0 1	$0 1	$0 1	$0 1	$0 1	$0 2	$0 2	$0 2	$0 3	$0 3	$0 4	$0 4	$0 5
Texas Retained Margin Increase	$4	$14	$0 0	$0 1	$0 1	$0 2	$0 1	$0 1	$0 1	$0 1	$0 2	$0 2	$0 3	$0 3	$0 3	$0 4	$0 5	$0 5
FERC Retained Margin Increase	$1	$3	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 1	$0 1	$0 1	$0 1	$0 1	$0 1	$0 1
SWEPCO Total Company Retained Margin	$9	$36	$0 0	$0 3	$0 3	$0 4	$0 2	$0 2	$0 3	$0 2	$0 5	$0 6	$0 8	$0 9	$0 8	$1 2	$1 3	$1 4

Congestion	NPV	Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Project Low Gas No Carbon			$2 2	$13 9	$14 4	$14 9	$15 6	$16 3	$17 1	$17 8	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5
Modeled Congestion/Losses - Zero after tie line in service			$2 2	$13 9	$14 4	$14 9	$15 6	$16 3	$17 1	$17 8	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5

PSO - SWEPCO North Central Wind Energy Facilities
Inputs - TIEC 2-2 P95 Low NoCO2

Year	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Allocation of Capacity to Jurisdictions.															
Arkansas															
Louisiana															
Texas															
FERC															
Total SWEPCO															
Oklahoma															
Total Project															
NPV Discount rate															
Off System Sales Margin Retained by AEP - Deduct fi															
Total Plexos OSS Margin by Case															
Margin Retention															
Arkansas															
Louisiana															
Texas															
FERC															

TIEC 2-2 SWEPCO Low No CO2 P95 Case PLEXOS Inpu

Net Production Cost Savings	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Project Low Gas No Carbon	$497 6	$511 6	$536 7	$536 7	$560 1	$580 0	$596 4	$618 2	$636 4	$653 8	$611 9	$627 8	$701 5	$729 9	$769 8
Baseline Low Gas No Carbon=P50 15% case	$593 7	$602 9	$625 0	$639 0	$656 4	$680 1	$709 8	$735 8	$761 6	$784 0	$784 2	$806 1	$885 4	$916 7	$940 3
Savings, pre-margin sharing pre Gen Tie	($96 1)	($91 3)	($88 4)	($102 3)	($96 3)	($100 2)	($113 3)	($117 6)	($125 2)	($130 3)	($172 2)	($178 3)	($183 9)	($186 9)	($170 6)
Less Lost energy value from losses on Gen Tie															
Lost GWh on Gen Tie	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual Average market Price-Load Hub ($ MWh)	49 2	50 5	51 8	53 6	55 6	57 0	57 9	59 7	62 4	64 5	65 7	67 6	68 3	69 0	69 6
Lost Energy Revenue ($MM)	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
Savings, pre-margin sharing	($96 1)	($91 3)	($88 4)	($102 3)	($96 3)	($100 2)	($113 3)	($117 6)	($125 2)	($130 3)	($172 2)	($178 3)	($183 9)	($186 9)	($170 6)

OSS Margin Savings

P95 Low Gas No Carbon Fundamentals ($ Millions)	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
SWEPCO Gross OSS Margin With Project	$36 79	$40 23	$43 78	$73 29	$72 79	$69 18	$94 91	$97 14	$115 30	$147 26	$152 20	$155 92	$130 47	$107 62	$97 57
SWEPCO Gross OSS Margin Without Project	$22 40	$39 90	$45 92	$50 02	$73 07	$70 89	$65 64	$66 75	$78 68	$105 57	$133 87	$136 15	$108 01	$87 91	$84 51
SWEPCO Gross OSS Margin Increase	$14 4	$0 3	($2 1)	$23 3	($0 3)	($1 7)	$29 3	$30 4	$36 6	$41 7	$18 3	$19 8	$22 5	$19 7	$13 1
Arkansas Margin Increase	$2 8	$0 1	($0 4)	$4 5	($0 1)	($0 3)	$5 6	$5 8	$7 0	$8 0	$3 5	$3 8	$4 3	$3 8	$2 5
La Margin Increase	$4 8	$0 1	($0 7)	$7 7	($0 1)	($0 6)	$9 7	$10 1	$12 1	$13 8	$6 1	$6 6	$7 4	$6 5	$4 3
Texas Margin Increase	$5 5	$0 1	($0 8)	$8 9	($0 1)	($0 7)	$11 2	$11 6	$14 0	$15 9	$7 0	$7 5	$8 6	$7 5	$5 0
FERC Margin Increase	$1 4	$0 0	($0 2)	$2 2	($0 0)	($0 2)	$2 8	$2 9	$3 5	$4 0	$1 8	$1 9	$2 2	$1 9	$1 3
Arkansas Retained Margin Increase	$0 3	$0 0	($0 0)	$0 4	($0 0)	($0 0)	$0 6	$0 6	$0 7	$0 8	$0 4	$0 4	$0 4	$0 4	$0 3
La Retained Margin Increase	$0 5	$0 0	($0 1)	$0 8	($0 0)	($0 1)	$1 0	$1 0	$1 2	$1 4	$0 6	$0 7	$0 7	$0 7	$0 4
Texas Retained Margin Increase	$0 5	$0 0	($0 1)	$0 9	($0 0)	($0 1)	$1 1	$1 2	$1 4	$1 6	$0 7	$0 8	$0 9	$0 8	$0 5
FERC Retained Margin Increase	$0 1	$0 0	($0 0)	$0 2	($0 0)	($0 0)	$0 3	$0 3	$0 4	$0 4	$0 2	$0 2	$0 2	$0 2	$0 1
SWEPCO Total Company Retained Margin	$1 4	$0 0	($0 2)	$2 3	($0 0)	($0 2)	$2 9	$3 0	$3 7	$4 2	$1 8	$2 0	$2 2	$2 0	$1 3

Congestion

Congestion	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Project Low Gas No Carbon	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$15 6
Modeled Congestion/Losses - Zero after tie line in service	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$18 5	$15 6

SOAH DOCKET NO. 473-19-6862

PUC DOCKET NO. 49737

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

REBUTTAL TESTIMONY OF

JAY F. GODFREY

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

FEBRUARY 12, 2020

TESTIMONY INDEX

SECTION PAGE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Jay F. Godfrey. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by American Electric Power Service Corporation (AEPSC), a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP), as Vice President - Energy Marketing and Renewables. AEP is the parent company of Southwestern Electric Power Company (SWEPCO or the Company) and Public Service Company of Oklahoma (PSO). AEPSC supplies engineering, financing, accounting, regulatory, and similar planning and advisory services to AEP's regulated electric operating companies, including SWEPCO and PSO (the Companies).

Q. ARE YOU THE SAME JAY F. GODFREY WHO FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is address the following assertions made by Texas Industrial Energy Consumers (TIEC) witness Charles Griffey and Cities Advocating for Reasonable Deregulation (CARD) witness Scott Norwood:

- I respond to Mr. Griffey's suggestion that SWEPCO should have used an all-source solicitation by describing the rationale for and benefits of the Company's Request for Proposals (RFP) to purchase wind facilities;
- I respond to Mr. Griffey's assertion that the Company could have deferred the decision to acquire the Selected Wind Facilities by explaining that the federal

Production Tax Credits (PTCs), which provide a substantial portion of the Facilities' benefits, will be phased out in the next several years; and

- I clarify Mr. Norwood's statement that SWEPCO retained an independent evaluator to oversee the bid evaluation by explaining that the independent evaluator was instead selected and retained by the Oklahoma Public Utilities Division and the Oklahoma Attorney General.

III. REBUTTAL TO MR. GRIFFEY

Q. TIEC WITNESS GRIFFEY AT PAGE 48 STATES THAT SWEPCO SHOULD HAVE OPENED AN ALL-SOURCE SOLICITATION, INCLUDING ALLOWING FOR WIND AND SOLAR RESOURCES TO OFFER PURCHASE POWER AGREEMENTS (PPAS). HOW DO YOU RESPOND?

A. I do not share the same concerns as TIEC witness Griffey. As I stated in my Direct Testimony and as described in Company witnesses Thomas Brice and John Torpey's Direct Testimonies, the Company identified wind generation resources as potential economic resources, not other resources such as solar or natural gas, for its generation portfolio in its Integrated Resource Plan (IRP) based on careful modeling of alternative resources. When the Company identifies a need for other resources through its IRP process, as described by Company witness Torpey, it will likely issue an RFP to procure appropriate resources. Further, as outlined in the direct testimony of Company witness Brice, the acquisition and ownership of the Selected Wind Facilities through Purchase and Sale Agreements (PSAs) provides unique benefits that present a higher value option for customers and at a lower risk versus a PPA.

Q. PLEASE EXPLAIN HOW THE COMPANY COULD RESPOND TO MARKET CHANGES BETTER THROUGH OWNERSHIP OF THE SELECTED WIND FACILITIES.

A. Ownership provides the Company the opportunity to control the facilities over their 30-year design life and the ability to react to changes that may not be available under a PPA structure, including repowering as I describe further below. As both the region's power supply and its supporting transmission system shift towards renewable generation, grid operators like Southwest Power Pool (SPP) will continue to evaluate and potentially modify their rules associated with scheduling and dispatch, forecasting, capacity markets, frequency regulations, smart inverter requirements, congestion and imbalance charges, ancillary services, and other requirements or revenue streams yet to be defined. With direct ownership and operational control over the Selected Wind Facilities, the Company will be in a position to react to these rule changes via operational adjustments or modification to systems in order to preserve and enhance benefits to customers.

In the event of market rule changes, the Company may not have the operational flexibility to mitigate risk and/or bring greater value to its customers with a PPA. The wind farm owner 1) may not be receptive to a PPA amendment to memorialize desired operational changes since they are already being compensated via the previously negotiated PPA terms, and 2) may not agree to operational changes due to complex financing structures used by third party owners that typically require financial participants' consent to such changes.

Q. PLEASE EXPLAIN HOW OWNERSHIP PROVIDES THE OPPORTUNITY FOR THE COMPANY TO IMPLEMENT CONGESTION MITIGATION MEASURES.

A. Ownership of the Selected Wind Facilities will provide the opportunity for the Company to implement potential congestion mitigation measures, including the construction of a generation tie-line or a transmission system upgrade, if economically beneficial. With a PPA, the Buyer has limited, if any, options to mitigate congestion for the term of the PPA. The Buyer could negotiate with the wind farm owner to implement solutions (such as a generation tie-line to an alternate point of interconnection or delivery), but the wind farm owner will not be incentivized to implement solutions if it increases their expenses and there is no PPA price adjustment.

Q. WHY IS OWNERSHIP OF THE SELECTED WIND FACILITIES MORE ATTRACTIVE THAN A PPA FROM AN END OF LIFE ASSET DISPOSITION PERSPECTIVE?

A. At the conclusion of the term of a PPA, which in many cases is not the end of life of the asset, the wind farm owner retains all rights to the assets. In contrast, at the end of the design life of the Selected Wind Facilities, the Company would own the wind turbines, associated infrastructure, interconnection facility, interconnection rights, and have control of the land rights and permits. Owning these assets provides the Company significant flexibility to provide additional benefits to its customers. Such options include 1) extracting the remaining value from the asset by continuing to operate wind turbines that have remaining life, 2) repowering the existing wind turbines, or 3) building new facilities. These options can all make use of the existing transmission and interconnection facilities. Ownership of the Selected Wind Facilities also provides the Commission the opportunity to evaluate the prudence of any future economic decisions in regards to repowering.

Q. WHAT ARE THE TECHNOLOGICAL BENEFITS ASSOCIATED WITH THE OWNERSHIP OF THE SELECTED WIND FACILITIES?

A. Ownership of the Selected Wind Facilities provides the Company the opportunity to take advantage of new technologies and strategies that increase customer benefits from the facilities. This technology includes the potential to use battery storage and the application of future turbine-improving performance technologies. General Electric, the turbine supplier, has shown a history of developing aftermarket enhancements (both software and hardware) for its turbine fleet, which has resulted in increased production, improved availability, and extended life of the wind turbines. Turbine enhancements on projects with PPAs would typically inure to the PPA counterparty instead of the Company and its customers.

Q. WHAT ARE THE BENEFITS TO OWNERSHIP IN REGARDS TO MANAGEMENT OF CREDIT RISK?

A. Engagement of a PPA introduces counterparty risk with the owner/developer for the contracted wind facilities for the term of the PPA. Independent Power Producers (IPPs) who are the owner/developers of contracted wind facilities generally lack the financial strength to provide necessary credit support to remedy a potential default under the PPA. Further, it reduces counterparty risk with the IPP and gives AEP a direct path to the vendor as it relates to equipment warranties and/or any upgrades.

Q. TIEC WITNESS GRIFFEY AT PAGE 49 STATES THAT "IF SWEPCO IS SEEKING TO FIX ENERGY PRICE VOLATILITY, IT COULD HAVE SOUGHT PPAS FROM OTHER POWER PROVIDERS TO DETERMINE WHAT THEY MIGHT OFFER." HOW DO YOU RESPOND?

A. Mr. Griffey's premise that SWEPCO is merely attempting to fix energy price volatility is not correct. As I describe above, the ownership of the physical assets affords a suite of benefits and provides an opportunity for the Company to give the guarantees described by Company witness Brice.

Q. TIEC WITNESS GRIFFEY AT PAGE 49 STATES, "RENEWABLE DEVELOPERS HAVE BEEN TAKING ON MORE MERCHANT RISK" AND THAT COMMERCIAL AND INDUSTRIAL (C&I) CUSTOMERS ARE NOT SIGNING CONTRACTS FOR THE FULL LIFE OF THE ASSETS. HOW DO YOU RESPOND IN REGARDS TO THE TERM LENGTH OF THE C&I RENEWABLE PPAS?

A. The trend to shorter contract lengths with C&I customers is generally based on Virtual Power Purchase Agreements (VPPA), the most common C&I renewable energy contract. Most of these C&I customers are not looking for their load to be served by these renewable projects; rather they are seeking to transfer the energy produced onto the grid and harvest the renewable energy credits (RECs) from the project. Under this type of structure, the output (power) would be sold (liquidated) into the market and then the RECs would either be retained by the C&I customer or retired on their behalf in order to meet their corporate sustainability goals. The Company recognizes that non-regulated or IPP renewable developers (those without obligation to serve regulated customers) have increasingly gravitated towards offering VPPAs to C&I customers in a contract-for-differences or hedge structure for a fixed term. Because these C&I customers are not seeking to lock up the renewable attributes for the life of the project, the only alternative is for the developer to price in and bear the merchant risk (and any potential benefits) over the remaining project life. In an ownership structure such as the Selected Wind Facilities, the Company and its customers are able to benefit from 1) the Production Tax Credit (PTC) in the first ten years, which buys down the cost of energy and 2) the value of the facilities' generation in the market for at least 30 years. VPPA's for C&I customers are not comparable to the Selected Wind Facilities for the reasons discussed above.

Q. TIEC WITNESS GRIFFEY AT PAGE 50 STATES, "IT IS UNREASONABLE FOR SWEPCO TO LOCK ITSELF AND ITS RATEPAYERS INTO A $1.1 BILLION INVESTMENT WHEN THE DECISION COULD BE DEFERRED." DO YOU AGREE?

A. No, I do not. As discussed in the direct testimony of Company witness Torpey, the Company's latest IRP shows a need for up to 1,200 MW of wind generation to be added by 2023 to provide energy cost savings and capacity benefits. As further discussed in my direct testimony, the Company therefore issued an RFP to determine if economical wind resources were available and to take advantage of the PTC. The PTC, which will expire soon and would be lost, helps to buy down the cost of energy for customers.

IV. REBUTTAL TO MR. NORWOOD

Q. CARD WITNESS NORWOOD AT PAGE 16 STATES THAT SWEPCO RETAINED AN INDEPENDENT EVALUATOR TO OVERSEE ALL PHASES OF THE BID ADMINISTRATION AND EVALUATION PROCESS. HOW DO YOU RESPOND?

A. As a point of clarification, C.H. Guernsey & Company (Guernsey) was selected and retained by the Oklahoma Public Utility Division and Oklahoma Attorney General as the Independent Evaluator to evaluate the PSO RFP process and bid administration, which was run in parallel with the SWEPCO RFP. Guernsey determined that PSO had followed the procedures outlined in the RFP and that the Company's bid evaluation and final project selections were appropriate.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

SOAH DOCKET NO. 473-19-6862

PUC DOCKET NO. 49737

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

REBUTTAL TESTIMONY OF

JOSEPH G. DERUNTZ

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

FEBRUARY 12, 2020

<u>TESTIMONY INDEX</u>

<u>SECTION</u> <u>PAGE</u>

<u>EXHIBITS</u>

<u>EXHIBITS</u>	<u>DESCRIPTION</u>
HIGHLY SENSITIVE EXHIBIT JGD-1R	Mechanical Load Analyses for the Selected Wind Facilities
EXHIBIT JGD-2R	Berkeley Lab Wind Project Lifetimes Study

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION IN THE COMPANY AND BUSINESS ADDRESS.

A. My name is Joseph G. DeRuntz. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP), as Project Director. AEP is the parent company of Southwestern Electric Power Company (SWEPCO, or the Company) and Public Service Company of Oklahoma (PSO). AEPSC supplies engineering, financing, accounting, and similar planning and advisory services to AEP's regulated electric operating companies, including SWEPCO and PSO.

Q. ARE YOU THE SAME JOSEPH G. DERUNTZ WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to respond to Texas Industrial Energy Consumers (TIEC) witness Jeffry Pollack's testimony regarding the useful life of the Selected Wind Facilities and the associated operation and maintenance (O&M) expenditures.

III. USEFUL LIFE OF THE SELECTED WIND FACILITIES

Q. TIEC WITNESS POLLOCK (AT PAGES 13 AND 14) QUESTIONS WHETHER IS IT REASONABLE TO EXPECT THAT THE SELECTED WIND FACILITIES WILL HAVE A 30-YEAR DESIGN LIFE. HOW DO YOU RESPOND?

A. I disagree with Mr. Pollock. As I explained in my direct testimony, the 30-year design life was a requirement to bid projects into the Request for Proposals (RFP) and the Selected Wind Facilities will be engineered to have a 30-year design life. To support a minimum 30-year design life, Bidders were required (RFP Section 3.8) to provide a Turbine Specific Site Suitability Report, which for the General Electric (GE) wind turbine is a Mechanical Loads Analysis (MLA). The MLAs evaluated the design load considering a 30-year design life, and, as applicable, identified recommended inspections and associated maintenance to support a 30-year design life, as outlined in Appendix I of the MLAs in HIGHLY SENSITIVE EXHIBIT JGD-1R. The Bidders, in general, and GE in particular, were in the best position to determine whether a 30-year life was feasible.

An increase in the life of the facilities over time is a natural progression and would be commensurate with advances in technology and experience with operation of wind farms. As shown in EXHIBIT JGD-2R, a recent survey found that wind project owners have increased their project-life assumptions over time and the current assumption average is 29.6 years. In fact, the majority of the responses to the survey in Exhibit JGD-2R assume a 30-year useful life for the projects, one respondent cited a 35-year useful life, and another cited a 40-year useful life. This demonstrates the increasing progression of useful lives of these types of facilities and that the 30-year design life of the Selected Wind Facilities is not unusually high, but in fact, is the most common useful life according to the survey in Exhibit JGD-2.

Taking all of this information into consideration, the 30-year design life for the Selected Wind Facilities is reasonable.

Q. TIEC WITNESS POLLOCK STATES (AT PAGE 15) THAT THE USEFUL LIFE FOR THE SELECTED WIND FACILITIES SHOULD BE DETERMINED BY THE INITIAL CAPITAL INVESTMENT. HOW DO YOU RESPOND?

A. Mr. Pollock's assertion is fundamentally flawed. Any wind facility, generating plant, or similar long life asset would require inspection and maintenance to ensure the initial capital investment is maximized and the expected design life achieved. The 30-year design life is realistic for the reasons stated above, and the Selected Wind Facilities' ongoing capital and O&M forecast is based on maintaining the availability and performance of the turbines through condition monitoring systems, routine preventative maintenance, planned corrective maintenance, and major maintenance and overhauls over 30 years of operation.

The ongoing capital and O&M projections for the Selected Wind Facilities are reasonable, were developed based on the known O&M operating agreement over the first ten years of operations, and consider the appropriate major maintenance and estimate of parts for the duration of the operational life.

Q. TIEC WITNESS POLLOCK MENTIONS (AT PAGE 13) THAT SWEPCO HAS NOT PROVIDED AN ONGOING CAPITAL CAP OR GUARANTEE FOR THE SELECTED WIND FACILITIES. WOULD SUCH A CAP OR GUARANTEE BE APPROPRIATE FROM AN OPERATIONAL PERSPECTIVE?

A. No, it would not. The Company has put forward a reasonable ongoing capital and O&M forecast that is available in Exhibit JGD-5 to my direct testimony. However, it would not be reasonable to set an ongoing capital cost cap for the duration of the life of the Selected Wind Facilities from an operational perspective. As with any generating plant, the ongoing capital and O&M at a facility is dependent on a variety of factors, some within the Company's control, and some beyond the Company's control. For example, if the Selected Wind Facilities have higher production than forecasted, the facilities will incur more wear and tear earlier and additional maintenance would be necessary. In addition, there are items included in the ongoing capital and O&M forecast that are beyond the Company's control and can change including escalation of property taxes, labor, and parts.

Finally, when the ongoing capital and O&M forecast was developed, the Company assumed these costs would be subject to periodic Commission reviews. Capping the Company's ongoing capital and O&M forecast is not appropriate because the forecast does not include risk pricing (contingency) for unknowns that could be experienced over the 30-year life of the project. Company witness Brice discusses the Company's cost cap guarantee and the inappropriateness of capping ongoing capital additions in his rebuttal testimony.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

CONFIDENTIAL IN ITS ENTIRETY

BERKELEY LAB
ELECTRICITY MARKETS & POLICY GROUP
emp.lbl.gov

September 2019

Benchmarking Anticipated Wind Project Lifetimes:
Results from a Survey of U.S. Wind Industry Professionals

Ryan Wiser and Mark Bolinger, Lawrence Berkeley National Laboratory

This paper draws on a survey of wind industry professionals to clarify trends in the expected useful life of land-based wind power plants in the United States. The expected useful life of a project affects expectations about its profitability, the timing of possible decommissioning or repowering, and its levelized costs.

We find that most wind project developers, sponsors and long-term owners have increased project-life assumptions over time, from a typical term of ~20 years in the early 2000s to ~25 years by the mid-2010s and ~30 years more recently. Current assumptions range from 25 to 40 years, with an average of 29.6 years.

The estimated average levelized cost of energy (LCOE) for new wind projects built in 2018 is $40.4/MWh (real 2018$), assuming a 20-year project life. With a 25-year useful life and no change in assumed operations and maintenance (O&M) expenditures or wind plant performance over time, LCOE declines by 10%, to $36.2/MWh, because capital costs are recovered over five additional years of production. At the now-common 30-year assumed life, levelized costs decrease another 7%, to $33.5/MWh (under the same unaltered assumptions about O&M and performance). Even longer assumed lifetimes lead to further (but diminishing) LCOE reductions—e.g., to $31.7/MWh and $30.3/MWh for 35- and 40-year lives, respectively.

The data and trends presented here may inform assumptions used by electric system planners, modelers and analysts. The results may also provide useful benchmarks to the wind industry, helping developers and assets owners to compare their expectations with those of their peers.

Methods

The findings in this paper largely draw from a brief survey of U.S. wind project developers, sponsors, financiers, and consultants. We distributed the survey to staff at 23 different organizations in August 2019. Responses were received from 21 staff at 18 of these organizations, for an overall (organizational) response rate of 78%. Additionally, we conducted a review of the annual financial reports from some of the large, publicly traded wind project developers and owners, yielding three additional sets of project-life assumptions.[1] Ultimately, we assembled 20 different time-series estimates of useful project life.[2]

Our interest was in better understanding how expectations for useful life have changed over time, as the industry has grown and matured. We focus on 'useful' life, defined here to mean the period of time in which the expected costs and revenues of a project are assessed to determine its economic viability. Typically, an asset with a useful life of, for example, 30 years is expected to earn ongoing operating profits during those 30 years (ongoing revenue > ongoing costs). At the end of year 30, however, either decommissioning or full

[1] In some cases, project-life assumptions that derive from financial reports reflect depreciation- or accounting-based lives, which may in theory differ from useful-life assumptions used by developers and sponsors. However, a review of our results indicates no such bias in the estimates reported later in this paper, as the distribution of responses is similar in both sources of data.
[2] These estimates, and other survey responses that we report later, come from staff and annual reports from: NextEra, RES, EDPR, Apex, Enel, Avangrid, EDF, Pattern, Scout, Leeward, MAP, Vestas, AEP, Berkshire Hathaway, JP Morgan, Wells Fargo, Clear Wind, Wood Mackenzie, and DNV GL.

project repowering would be expected. A longer assumed project life may enhance the expected long-term profitability of a project, assuming any resulting increase in O&M is kept within reasonable bounds. Moreover, longer depreciation terms reduce annual book depreciation from an accounting perspective, thereby boosting net income in the near term. From a planning and modeling perspective, meanwhile, longer lifetimes may enable lower LCOE by recovering up-front capital costs (and, potentially, any component replacement or refurbishment costs) over additional years of electricity production.

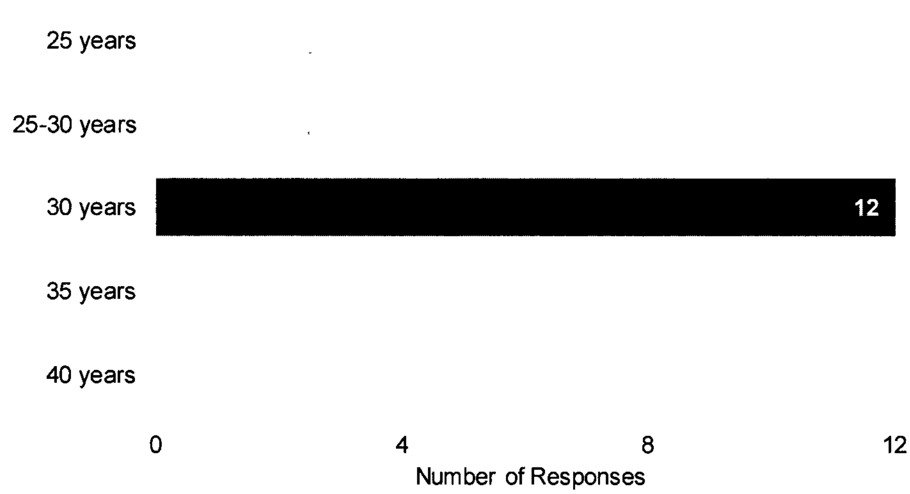
We focused on expectations from project developers, sponsors, and long-term owners because these are the entities most likely to be thinking about the full lifecycle of a project. However, we recognize that each participant in a wind project may have different perspective on what 'project life' means, or how it matters. A lender, for example, will primarily care about the revenue and costs of a project over the term of the loan: often 15 years or less. Tax equity providers may focus on the first 10-12 years, during which their returns are earned. Engineers might think of the certified life of the turbines (20 years historically, but now 25, 30 or even 40 years in some cases), or the engineering design life of the project. Providers of operations and maintenance services might consider the lifetime of any O&M contracts.

We specifically sought insights into assumptions that project developers, sponsors and long-term owners most-commonly use for project life, when considering the lifetime profitability of a project, pitching projects to financiers, and establishing power purchase agreements (PPAs) during the development and financing process. We also included major consultancies in our sample, including those that provide due diligence services to the wind industry. We asked about current assumptions, and how those assumptions have changed over time. Some respondents offered additional insights, which we share as appropriate.

Estimated Project Lifetimes

Project developers, sponsors, and long-term owners now most-commonly assume 30-year useful project lives, as depicted in Figure 1.

Figure 1. Current Useful-Life Expectations for Wind Plants



Specifically, twelve sources cited 30 years, three cited 25-30 years (averaged to 27.5 years in Figure 2), three cited 25 years, one cited 35 years, and another cited 40 years.[3] None of the respondents uses a 20-year project life assumption; several respondents also noted that they are not aware of others in the wind industry still using a 20-year assumption.

Expectations for the useful life of wind projects vary by respondent, but have consistently increased over time—from a typical value of ~20 years in the early 2000s and prior, to ~25 years by the mid-2010s, and then to ~30 years most recently (Figure 2, Table 1). The average among respondents for 2019 is 29.6 years.

Figure 2. Useful-Life Expectations for Wind, over Time

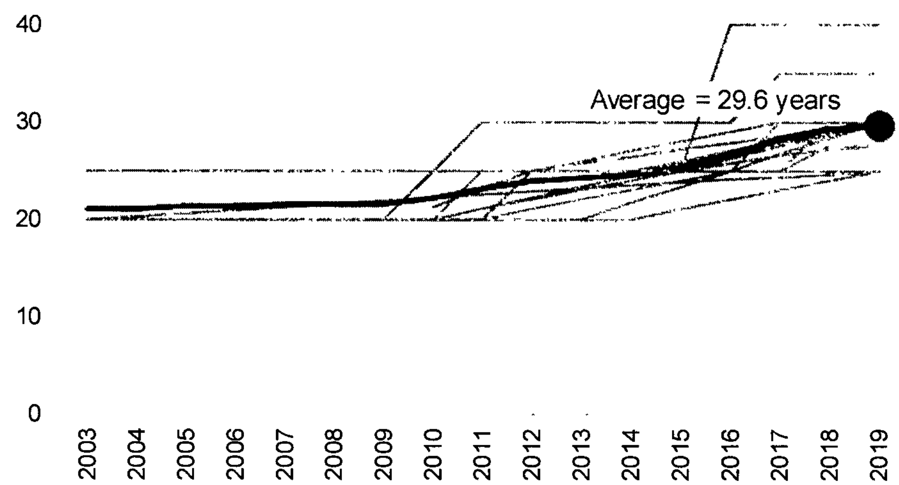


Table 1. Summary of Respondent Estimates of Useful-Life Expectations for Wind Projects

Source 1	25	25	25	25	25	25	25	25	30	30	30	30	30	30	35	35	35
Source 2										25	26	27	28	29	30	30	30
Source 3	25	25	25	25	25	25	25	25	25	25	25	25	26	27	28	29	30
Source 4	20	20	20	20	20	20	20	20	25	25	25	25	25	25	30	30	30
Source 5								21	23	25	26	26	27	28	29	29	30
Source 6	20	20	20	20	20	20	20	20	20	25	25	25	25	25	25	30	30
Source 7													25	40	40	40	40
Source 8	20	20	20	20	20	20	20	25	25	25	25	25	25	25	30	30	30
Source 9	20	20	20	20	20	20	20	20	21	22	23	24	26	27	28	29	30
Source 10																	30
Source 11									25	25	25	25	25	25	30	30	30
Source 12	20	20	20	20	20	20	20	20	20	20	20	20	21	22	23	24	25
Source 13								25	25	25	25	25	25	26	28	29	30
Source 14	20	20	20	20	20	20	20	20	20	20	20	22	23	25	27	28	30
Source 15			25	25	25	25	25	25	25	25	25	25	25	25	25	27.5	27 5
Source 16																	30
Source 17	20	20	20	20	20	20	20	20	21	22	23	24	25	26	27	27	27 5
Source 18																	27.5
Source 19									20	21	22	23	24	25	25	25	25
Source 20	20	20	21	21	21	22	22	22	23	23	23	23	24	24	24	25	25
AVERAGE	21.0	21.0	21.4	21.4	21.5	21.5	21.5	22.2	23.2	23.9	24.3	24.7	25.2	26.7	28.4	29.3	29.6
# Responses	*10*	*10*	*11*	*11*	*11*	*11*	*11*	*13*	*15*	*16*	*16*	*16*	*17*	*17*	*17*	*17*	*20*

[3] The firm applying a 40-year assumption notes, however, that this assumption is capped at the term of each project's lease, resulting in a fleet-wide average useful life of 31 years. Moreover, the firm is not altogether clear as to whether the 40-year life applies to entire wind projects, or instead to just certain components of those projects and turbines.

Drivers and Influences

In addition to these numerical estimates, many respondents offered insight into how they or the industry treat project life. Though we do not seek to synthesize generalizable findings from these insights, they do enhance understanding of industry thinking, and so are summarized below where relevant:

- Some respondents noted that turbine design certifications are often 20 years, though some manufacturers are moving towards or already provide 25-, 30-, or even 40-year certifications depending on the turbine and wind regime. Moreover, O&M servicing agreements sometimes (albeit rarely) extend to 25- or even 30-years. Such service agreements may not cover component replacement, and so project owners may still face O&M risk. Nonetheless, in general, these points suggest that the major manufacturers are increasingly comfortable with 30-year lifespans.
- One respondent pointed out, however, that project owners need not equate turbine certification lives with the useful, economic, or depreciable life of a wind power asset. Owners will conduct project-specific engineering and economic analysis to inform useful-life assumptions, considering local wind conditions, expected project revenue, and O&M and refurbishment expectations. As such, regardless of the details on turbine certification and servicing contracts, 30-year lifetimes are now the most common, though a number of developers and sponsors continue to use 25 years or a range of 25-30 years.
- Multiple developers revealed that key factors in increased project lives include technology maturity and robustness, as well as improved understanding of performance, wear-and-tear, and O&M practices. Projects from the 1980s and 1990s continue to operate today in some cases, turbines in the 1+ MW class have growing operating history, and engineering and operational skill and turbine sophistication has dramatically increased. As older projects have reached their design lifetimes, the industry has found ways to extend those lifetimes. Turbine control regimes that clip production to manage fatigue loads and ensure that turbines stay within their design envelope have become increasingly common. One major independent engineering firm agrees that, if taken care of, a facility should last 25-30 years or longer with proper maintenance protocols and, for some components such as gearboxes, plant refurbishment. The recent emergence of 'partial' repowering whereby certain turbine component are replaced and/or upgraded has bolstered confidence in longer useful lives (at least for those turbines that are being refurbished), as have enhanced O&M options and lower overall O&M costs.
- The O&M implications of extended useful lives are uncertain. Some turbine components can easily last 30+ years whereas others, such as gearboxes, would likely require refurbishment or replacement. While acknowledging uncertainty in future O&M costs, a limited number of respondents indicated that they do not anticipate a fundamental step-change in O&M expenditures to achieve 25-year lives. Others indicated that heightened O&M costs and component refurbishment and replacement go hand-in-hand with extended project life, as might increased performance degradation, especially to achieve 30-year life spans—also noting that these effects are factored-in when assessing overall plant profitability and determining useful life. Ultimately, the actual useful life of wind assets will depend critically on how components wear over time, which will affect O&M expenditures.
- Another factor in extended project lives is the desire, and perhaps even need, to capture project value/economics beyond the initial 10-20 year life that is usually covered by the first power purchase agreement (PPA). The extent of this post-PPA (and post-PTC) 'merchant' value is often an item of wide disagreement within the industry, and depends on the trajectory of both power prices and O&M costs. Two respondents noted that today's low wholesale power prices were generally not anticipated a decade ago, challenging post-PPA project economics for older projects. Nonetheless, especially as PPA

terms have tended to shorten over time and competition for those PPAs has strengthened—resulting in lower PPA-derived revenue—an increasing number of projects need to demonstrate some post-PPA value in order for the project to pencil out from an overall return-on-investment perspective. These trends have pushed the industry to more fully investigate longer useful lives. Ultimately, though, whether this post-PPA value materializes will depend on O&M requirements as projects age and, critically, on future wholesale power price developments. These two factors, post-PPA revenue and O&M costs, are generally viewed as the two most uncertain aspects of project life estimates.

- Developers indicated that different owners treat and model project life somewhat differently. For example, one respondent indicated that its firm has historically modeled 25-year project lives as 20 years of revenue plus a terminal value (which is equated to 5 years of net revenue); a separate respondent indicated that this approach was very common earlier in the 2000s. Another respondent mentioned that its company typically assumes 25 years, but with the final 5 years subject to production degradation. An independent engineer revealed that, over the last several years, it has noticed that longer lifetimes have been supported by increasingly sophisticated engineering and economic analysis, whereas previously that analytical support was often somewhat lacking.
- Regional variation in project life assumptions may also exist. Wind plants located in areas with liquid wholesale markets (ERCOT, SPP, MISO, etc.) that enable projects to readily go merchant once the initial PPA expires are more likely to use an assumed life of 30 years. Projects located in illiquid markets (WECC, SERC, FRCC) and selling to an electric utility may more-regularly assume a project life equivalent to the term of the PPA—typically less than 30 years.
- One sponsor remarked that it reviews the estimated useful lives of its assets on an ongoing basis and that, in 2016, this review indicated that many of its wind projects were expected to last longer than previously estimated for depreciation purposes. As a result, the useful lives of certain wind assets[4] were increased from 25 years to 40 years, capped at the land lease term if lower, to better reflect the periods during which these assets are expected to remain in service. The weighted-average useful life of its wind projects was consequently 31 years, and the company is assessing lease extensions to potentially further increase the average useful life of its collective wind assets.
- Another developer and owner reported that it opted to conduct a rigorous independent assessment of its fleet in the early 2010s, taking into account local wind conditions and assessing lifetime both from a structural and economical perspective. From a structural point of view, it analyzed structural components that could not be reasonably replaced, conducting extreme load and fatigue analyses on 37 wind projects, representative of the conditions of all 161 wind projects in its fleet at the time. This owner concluded that, for all wind projects analyzed, failure rates for these components would be lower than 0.5% during a period of 25 years. In parallel, this owner conducted an economic analysis to ensure that operating each of the projects was profitable during these 25 years. Estimated costs were compared with expected revenues, and in all cases, expected revenues remained above expected operational costs during the 25-year lifetime of the assets. Finally, a thorough analysis was conducted to make sure no project had any contractual, land lease, environmental or legal restriction that would prohibit extending operations to 25 years.
- Another large asset owner noted that, in 2017, a review indicated that the actual lives of its wind plants were expected to be longer than the lifetime previously estimated for depreciation purposes. As a

[4] As indicted earlier, this firm is not altogether clear as to whether the 40-year life applies to entire wind projects, or instead to just certain components of those projects and turbines.

result, this wind plant owner changed the estimated useful lives of wind plant equipment from 30 years to 35 years, better reflecting the period during which these assets are expected to remain in service. The resultant accounting reduction in annual book depreciation had the effect of boosting near-term annual net income estimates.

- Yet another developer indicated that it recently increased its useful life assumption from 25 years to a project-specific range of 25 to 30 years. Whether a project is assumed to have a 25-year or a 30-year useful life depends on detailed analysis that considers turbine model, foundation design, wind regime, O&M expectations, merchant-tail revenue expectations, land lease terms, and other considerations. In effect, an 'optimal' useful life is determined, through detailed analysis, for each project.
- An independent engineer cited foundation design as often the governing factor, but further noted that foundations are now commonly designed with a 30-year design life in mind. This respondent indicated that 30-year useful lives are now always employed in project-sale transactions, with shorter terms sometimes the focus in tax equity transactions and debt deals. A 25-year life used to be a stretch in the assumptions, and was not typically considered in most financings (the exception being sale-leaseback tax equity deals, but those were never prevalent). That has now changed, especially over the last few years as 30-year lifetime assumptions have become common.
- A prospective owner revealed that it recently issued an RFP for a large volume of wind that specified that it was looking to buy (at completion) 30-year design life projects with 30-year design life turbines. The solicitation further required wind developers to provide a mechanical load analysis (or equivalent) from the wind turbine manufacturer to support the design life assumption. The owner reached out to the major turbine manufacturers prior to issuing the RFP, confirming that each of those manufacturers could meet the requirement depending on the wind regime, albeit with high O&M costs to be expected in the later years.
- One respondent cited an accounting perspective as a primary driver for recent increases in assumed lifetimes: longer depreciation terms reduce annual book depreciation from an accounting perspective, thereby boosting near-term net income (all else being equal). This same respondent observed that increases in assumed project lives correlated (in time) with a move in the industry to capitalize (and therefore depreciate, not expense) major operating expenses such as gearbox replacements.
- Tax equity and lenders are often less-impacted by project term. Lenders are generally focused on ensuring that loans are repaid during the term of the PPA—before the project has merchant exposure. Tax-equity providers are similarly not always overly concerned with project life, but rather with the first 10+ years or so of operation, and making sure that energy generation matches expectations such that federal tax incentives are fully captured. This is not to say that longer project lives are ignored by these project participants, but only that useful life—whether 25- or 30-years—is less often a governing factor in investment decisions.
- One financier declared that it tends to have a somewhat more conservative view—using 25 years as the technical and economic lifetime, albeit acknowledging that many others have gained comfort with 30 years. This respondent also indicated that the actual incremental value of years 25 to 30 is generally quite low in present value terms, especially if there is need for increased O&M or refurbishment.
- Finally, an independent engineer suggested that, in the future, further extensions to project life might be enabled by even-more-sophisticated control strategies that seek to maximize overall lifetime plant profitability, by trading off immediate power production (especially when wholesale power prices are

very low) against plant-lifetime 'consumption' and O&M costs. While these strategies are not yet employed broadly, the computational tools and expertise exist to potentially self-curtail during periods of high fatigue and low wholesale prices, thereby reducing future O&M costs and extending project life. Moreover, in the wake of a phased-out PTC, such strategies could become more common as the current PTC-induced emphasis on near-term production begins to shift in favor of longer-term considerations.

Impacts on Levelized Cost of Energy

The estimated average levelized cost of energy (LCOE) for new wind projects built in 2018 is $40.4/MWh (real 2018$), assuming a 20-year project life and excluding the impacts of the federal production tax credit (Figure 3).[5] With a 25-year useful life and no change in assumed operations and maintenance (O&M) expenditures or project performance over time, LCOE declines by 10%, to $36.2/MWh because capital costs are recovered over five additional years of production. At the now-common 30-year assumed life, levelized costs decrease another 7%, to $33.5/MWh (again, all else equal). Even longer assumed lifetimes lead to further, but diminishing (due to discounting), LCOE reductions—to $31.7/MWh and $30.3/MWh for 35- and 40-year lives, respectively. These estimates assume that O&M costs simply scale with inflation regardless of useful life and that performance degradation as projects age is not present. Consequently, the analysis overstates the benefits of extended project lifetimes on LCOE, though is still suggestive of a potentially significant positive influence, at least among the nearer-term extensions from 20 to 25 to 30 years (whereas discounting erodes the benefits of longer-term extensions from 30 to 35 to 40 years).

Figure 3. Levelized Cost of Wind in 2018, by Project Life (2018$/MWh)

Project lifetime is not as impactful as installed costs and annual electricity production for determining the overall levelized cost of wind energy. Nonetheless, if O&M costs can be contained, project life is one of several levers (that also include financing and O&M) that helps reduce the levelized cost of wind energy.

[5] These LCOE estimates apply empirical data and assumptions for installed costs, O&M costs, capacity factors, and financing from Wiser, R. and M. Bolinger. 2019. *2018 Wind Technologies Market Report.* Washington, DC: U.S. Department of Energy.

BERKELEY LAB ELECTRICITY MARKETS & POLICY GROUP emp.lbl.gov

Acknowledgements

For his support of this research at the U.S. Department of Energy, we thank Patrick Gilman. We also acknowledge Rich Tusing at the National Renewable Energy Laboratory for his contributions. We especially thank each of the wind industry professionals who thoughtfully responded to our questions. For reviewing an earlier version of this manuscript, we thank five of the survey respondents, as well as Trieu Mai and Eric Lantz (NREL). Lawrence Berkeley National Laboratory's contributions to this report were funded by the Wind Energy Technologies Office, Office of Energy Efficiency and Renewable Energy of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The authors are solely responsible for any omissions or errors contained herein.

Disclaimer and Copyright Notice

For more information on the Electricity Markets & Policy Group, visit us at https://emp.lbl.gov/
For all of our downloadable publications, visit https://emp.lbl.gov/publications

BERKELEY LAB
Bringing Science Solutions to the World

ELECTRICITY MARKETS & POLICY GROUP
ENERGY ANALYSIS & ENVIRONMENTAL IMPACTS DIVISION

SOAH DOCKET NO. 473-19-6862

PUC DOCKET NO. 49737

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

REBUTTAL TESTIMONY OF

KARL R. BLETZACKER

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

FEBRUARY 12, 2020

TESTIMONY INDEX

SECTION PAGE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Karl R. Bletzacker. My position is Director, Fundamentals Analysis, American Electric Power Service Corporation (AEPSC). AEPSC supplies engineering, financial, accounting, planning and advisory services to the electric operating companies of American Electric Power Company, Inc. (AEP), including Southwestern Electric Power Company (SWEPCO or the Company). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. ARE YOU THE SAME KARL R. BLETZACKER WHO FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the positions brought forward by Office of Public Utility Counsel (OPUC) witness Karl Nalepa and Texas Industrial Energy Consumers (TIEC) witnesses Jeffry Pollock and Charles Griffey that are based upon their allegation that NYMEX natural gas futures prices are a suitable substitute for the Company's natural gas price forecast. Likewise, I counter Mr. Griffey's similar substitution of Intercontinental Exchange Southwest Power Pool (SPP) South power futures contract prices for the Company's SPP Central power price forecasts. Subsequently, I address Messrs. Griffey and Pollock's misleading comparison of the Company's weather-normal natural gas price forecast to actual spot prices and

NYMEX natural gas futures prices. Ultimately, I complete the picture by displaying every natural gas price forecast in the Company's possession since 2018 that was delivered to Mr. Griffey through the discovery process along with the EIA AEO 2020 and a comparison to SWEPCO's Break-Even natural gas price. I also demonstrate that the risk to the electric power industry of incurring carbon emission costs in the future <u>is not zero</u> and eliminating all consideration of potential carbon burden impacts, as suggested by Mr. Pollock, is unreasonable. Finally, I refute Messrs. Griffey and Pollock's claim that the Company overstates SPP power prices as evidenced by natural gas implied heat rate projections.

<u>III. NYMEX NATURAL GAS FUTURES CONTRACT PRICES ARE NOT A SUITABLE LONG-TERM FORECAST OF NATURAL GAS PRICES</u>

Q. DO YOU AGREE WITH MESSRS. GRIFFEY, POLLOCK, AND NALEPA'S ASSERTION THAT NYMEX NATURAL GAS FUTURES PRICES SHOULD BE SUBSTITUTED FOR THE COMPANY'S FUNDAMENTALS FORECAST FOR EVALUATION OF THE SELECTED WIND FACILITIES?

A. No. Substitution of NYMEX futures prices for the Company's model-driven assessments of the balance of supply, demand and resulting natural gas price is invalid for the following reasons:

1) The NYMEX natural gas futures contract is priced for uniform hourly and daily rates of flow over the course of the delivery month. In contrast, the Company's natural gas price forecasts are: i) projections of daily spot prices presented as monthly or yearly averages (of those daily spot prices); ii) not volume-specific throughout the month; and iii) inclusive of prices associated with intra-month periods of both high and low daily demands.

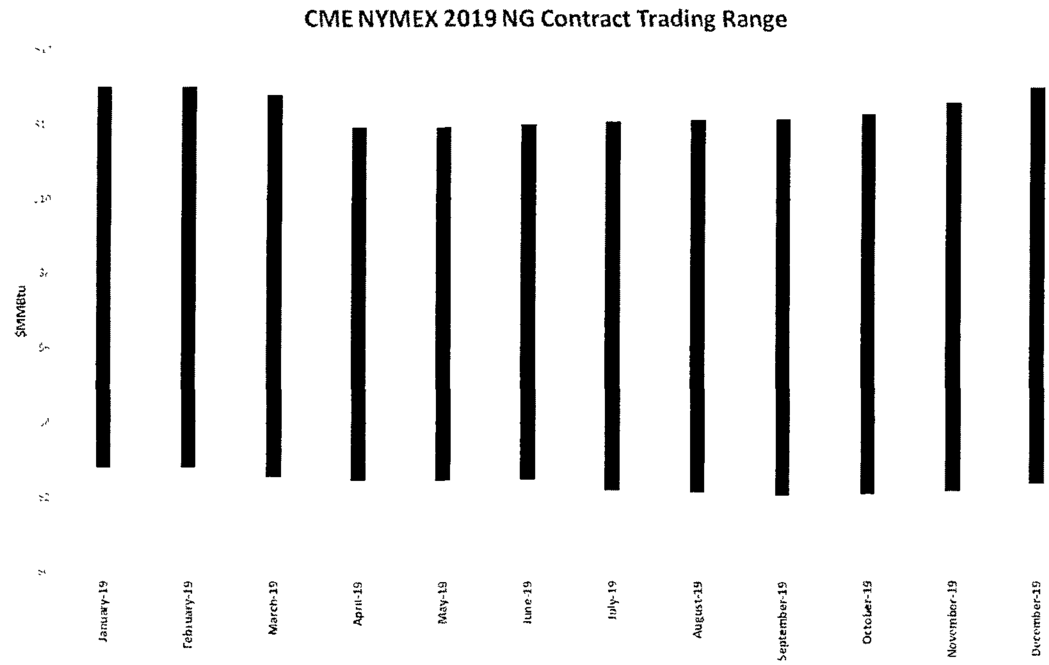
2) NYMEX natural gas futures contracts are not available at all beyond the next twelve years. Intervenor witnesses who suggest using NYMEX futures must create their own methodology for the extension ("trending") of these prices. This "trending" is devoid of any fundamentals insight. The Company's natural gas price forecasts are modeled for thirty-five years.

3) NYMEX natural gas futures contracts are functionally illiquid beyond the near term (~2 years) as shown by Open Interest (the total number of open futures contracts). Furthermore, price propositions shown for this functionally illiquid period beyond 2 years may not reflect actual transactions. NYMEX system-generated prices are not derived from any fundamental market information but instead are inserted by NYMEX. Should any attempt be made to purchase natural gas futures contracts in this illiquid period, the increased demand would likely run up prices. The lack of futures market liquidity beyond the near term does not provide clarity even to traditional energy futures market participants.

4) NYMEX natural gas futures contracts (that exist only in the near future) are acquired mostly for hedging. Hedging a future price (e.g., locking-in a fixed price to escape volatility), or price spreads between time periods (e.g., natural gas storage injections and withdrawals) or between natural gas and another commodity (e.g., the natural gas and electricity "spark spread") reduces the risk associated with adverse price movements. <u>Hedgers are indifferent to the future spot market price of natural gas</u> – they are only interested in a fixed price or a fixed spread between prices. The trading activity of hedgers has the potential to be incorrectly interpreted as price discovery for the future natural gas market.

5) 5) The twelve-year life of a NYMEX natural gas futures contract will present a range of trading values. "Trading range" is the difference between the high and low prices for a given NYMEX natural gas futures contract, i.e., a future month. Figure 1 below illustrates the trading ranges of the January 2019 through December 2019 NYMEX natural gas futures contracts. The average trading range of these NYMEX natural gas futures contracts was $10.02/MMBtu. Upon expiration, each NYMEX futures contract will settle to a terminal value and converge to the actual value of natural gas at the Henry Hub, but a snapshot of those trading values at any given point over the contract's lifetime provides no insight as to what that value may ultimately be.

Figure 1



Q. DO YOU AGREE WITH TIEC WITNESS POLLOCK'S CLAIM THAT NYMEX FUTURES CONTRACT PRICES REPRESENT ACTUAL TRANSACTIONS?

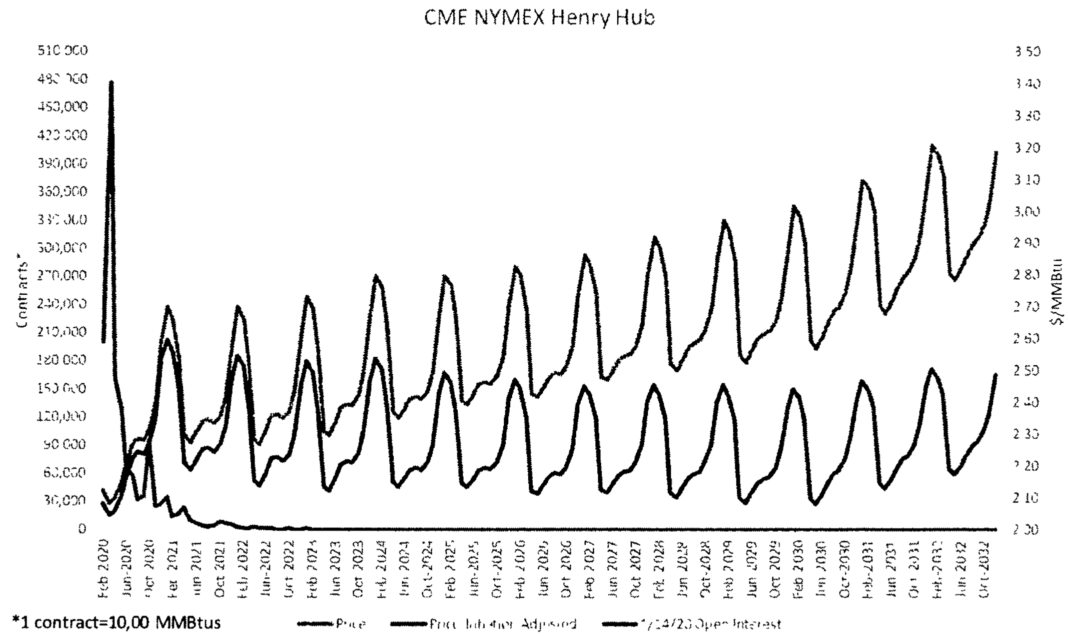
A. Only to a very limited degree. Mr. Pollock's claim that "futures contract prices represent actual transactions between buyers and sellers who put real money at risk in their day-to-day operations" (Pollock Direct Testimony, page 20, lines 20-21) does not recognize that: 1) ten of the twelve years of NYMEX futures contract prices have little, or no, open interest (i.e., no actual contracts), and; 2) CME Group (owner of the NYMEX) inserts a "system-generated price" wherever actual trading data is unavailable[1], so NYMEX futures contract prices do not usually represent actual transactions beyond the first couple of years.

[1] *https://www.cmegroup.com/confluence/display/EPICSANDBOX/Settlement+Prices*

Q. WOULD YOU PROVIDE A RECENT DEPICTION OF NYMEX NATURAL GAS FUTURES CONTRACT OPEN INTEREST FOR THE ENTIRE TWELVE YEAR TRADING PERIOD?

A. Yes. Beyond two years, the NYMEX natural gas futures contract has little, or no, open interest as described in my Direct Testimony (page 8, fig. 2). That testimony is not addressed or contradicted by intervenor witnesses. Figure 2 below illustrates that, as of 1/14/2020, there is little, or no, open interest after next winter (2020-2021). NYMEX natural gas futures contract "actual" prices, along with the "theoretical" (NYMEX system-generated) prices, are also presented in both nominal and inflation-adjusted ("real") dollars. The overall negative slope of NYMEX natural gas futures contract prices expressed in inflation-adjusted dollars is alarming because it implies that, at some point into the future, NYMEX natural gas futures contract prices would be zero.

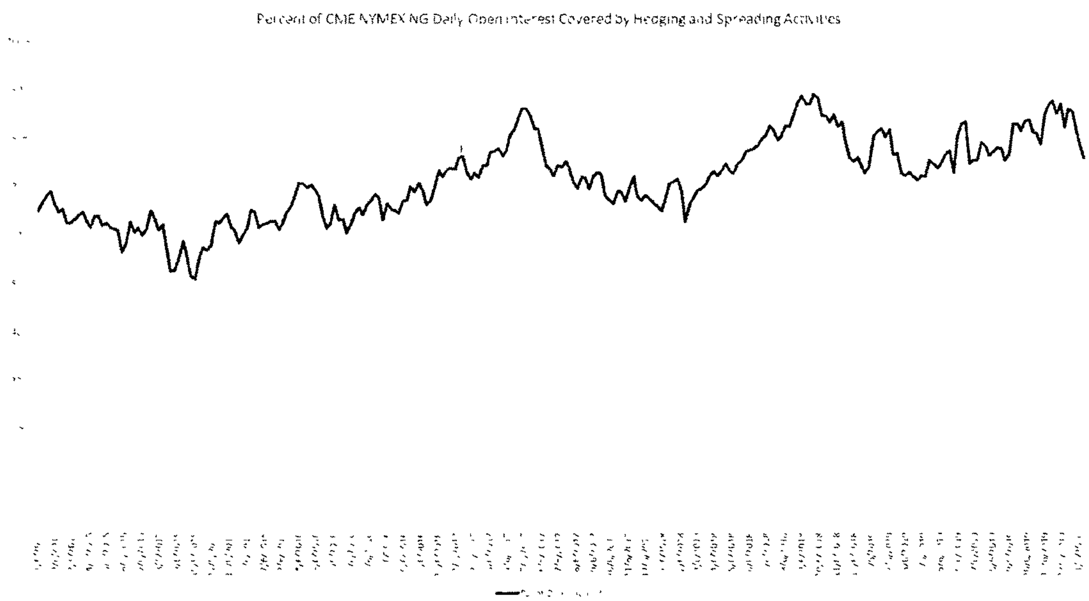
Figure 2



Q. WHAT PERCENTAGE OF NYMEX NATURAL GAS CONTRACT TRADING IS REPORTED AS HEDGING AND SPREADING?

A. The U.S. Commodity Futures Trading Commission is an independent governmental agency that regulates the US futures markets and publishes the Commitments of Traders reports to help the public understand market dynamics with position data supplied by supporting firms. Figure 3 illustrates the percentage of total open interest reported as: i) hedging, and; ii) spreading as reported by the U.S. Commodity Futures Trading Commission from 2015 to date. The Figure shows the percentage of open interest that consists of hedging and spreading ranges from approximately 50-90% and averages about 70%. It is evident that the vast majority of all NYMEX natural gas trades are not providing any credible insight into future Henry Hub spot prices because hedgers are escaping volatility and are indifferent to the future spot market price of natural gas.

Figure 3



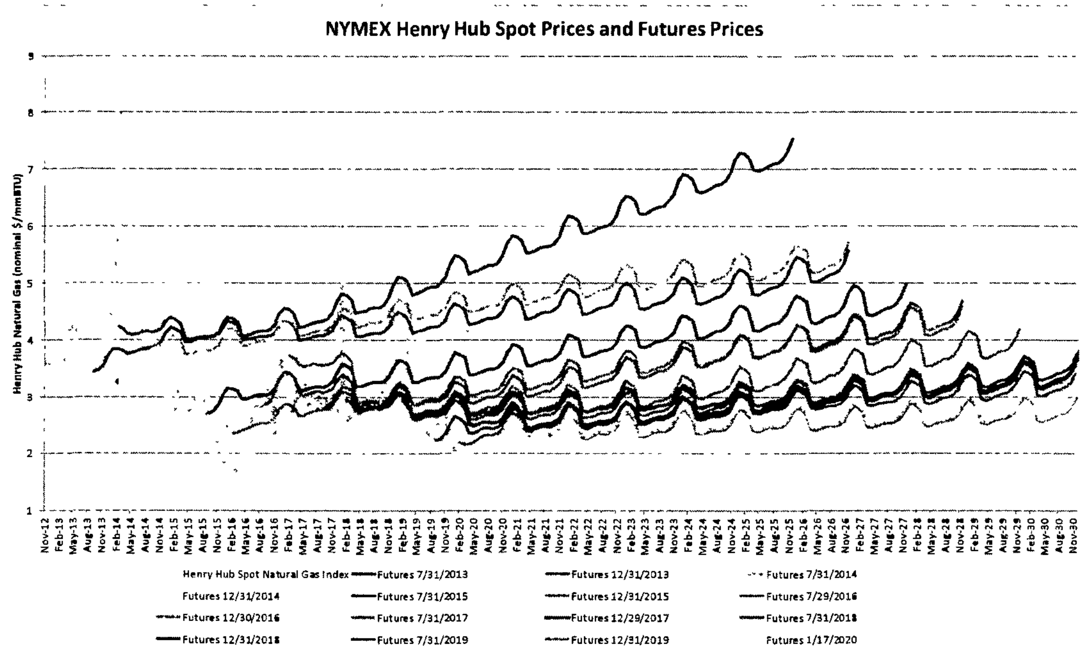
Q. DO YOU AGREE WITH TIEC WITNESS POLLOCK'S RECOMMENDATION THAT NYMEX NATURAL GAS FUTURES PRICES SHOULD BE USED BY THE COMMISSION FOR EVALUATING SWEPCO'S PROPOSED PROJECT?

A. No. Mr. Pollock's recommendation that the Commission should "look to" NYMEX natural gas futures prices (Pollock Direct Testimony, page 22, lines 20-21) is erroneous for the reasons already described. Furthermore, Mr. Pollock has extended NYMEX futures prices beyond their twelve-year trading period with gas prices resulting from his own inferred values and escalation rate (Pollock Direct Testimony, page 21, lines 10-12 and table 5). Mr. Pollock then represents that he has evaluated the projected net benefits (Pollock Direct Testimony, page 23, lines 3-12) of the Selected Wind Facilities "based on the NYMEX futures prices," but in reality, he has created two-thirds of the natural gas prices for his testimony.

Q. OPUC WITNESS NALEPA COMPARED NYMEX NATURAL GAS FUTURES CONTRACT PRICES TO THE COMPANY'S BREAK-EVEN NATURAL GAS PRICE. WHAT DO YOU CONCLUDE FROM HIS COMPARISON?

A. Mr. Nalepa's comparison (Nalepa Direct Testimony, page 28, figure 4) illustrates that in the last 8 months, his representation of "NYMEX" (Nalepa-"trended" NYMEX natural gas futures contract prices) has changed by approximately 20 percent. Figure 4 further illustrates the remarkable volatility of the NYMEX natural gas futures contract prices over time. This underscores that any investment analysis based upon trended NYMEX natural gas futures contract values represents only one day of futures prices and is further subject to potentially rapid changes.

Figure 4



Q. DO YOU AGREE WITH OPUC WITNESS NALEPA'S ASSERTION THAT THE COMMISSION SHOULD NOT IGNORE THE IMPACT OF NYMEX FUTURES CONTRACT PRICES?

A. No. Mr. Nalepa's assertion that the Commission should not "ignore the impact of NYMEX futures prices" (Nalepa Direct Testimony, page 28, lines 10-15 and page 29, lines 1-3) is supported only by his claim that it is "unchallenged that in the short term, the NYMEX futures prices are a much better reflection of market conditions than are the fundamental forecasts." In addition to his unsupported claim, he offers no definition of "short term." Given: 1) the NYMEX natural gas futures contract is available for only 12 years and the analysis of the Selected Wind Facilities customer benefits extends 30 years; 2) NYMEX natural gas futures contract prices have little, or no, open interest (actual contracts) beyond next winter, and; 3) NYMEX natural gas futures contract prices have displayed remarkable volatility as shown in Figure 4 above and in his own Figure 4 (page 28), Mr. Nalepa's recommendation to the Commission is unsubstantiated.

Q. DO YOU AGREE WITH TIEC WITNESS GRIFFEY'S COMPARISON OF A SINGLE DAY OF NYMEX NATURAL GAS FUTURES CONTRACT PRICES TO THE COMPANY'S NATURAL GAS PRICE FORECASTS?

A. No. Mr. Griffey's comparison of the Company's Base (No CO_2) and Low (No CO_2) natural gas price forecasts to single-date futures contract prices and his calculation of a precise percentage differential (Griffey Direct Testimony, page 20, lines 3-13 and figure 3) has the same flaws exhibited in Mr. Nalepa's testimony; NYMEX prices for a single day are subject to potentially rapid changes and are not a suitable long-term forecast of Henry Hub natural gas spot prices.

Q. DO YOU AGREE WITH TIEC WITNESS GRIFFEY'S ASSERTION THAT SWEPCO'S FIVE-YEAR FORWARD PURCHASE OF NATURAL GAS, PURSUANT TO LOUISIANA PUBLIC SERVICE COMMISSION (LPSC) ORDER, IS PROOF THAT THE QUOTED NYMEX PRICE IS AN ACCURATE REFLECTION OF ACTUAL FORWARD PRICES AT LEAST SIX YEARS INTO THE FUTURE?

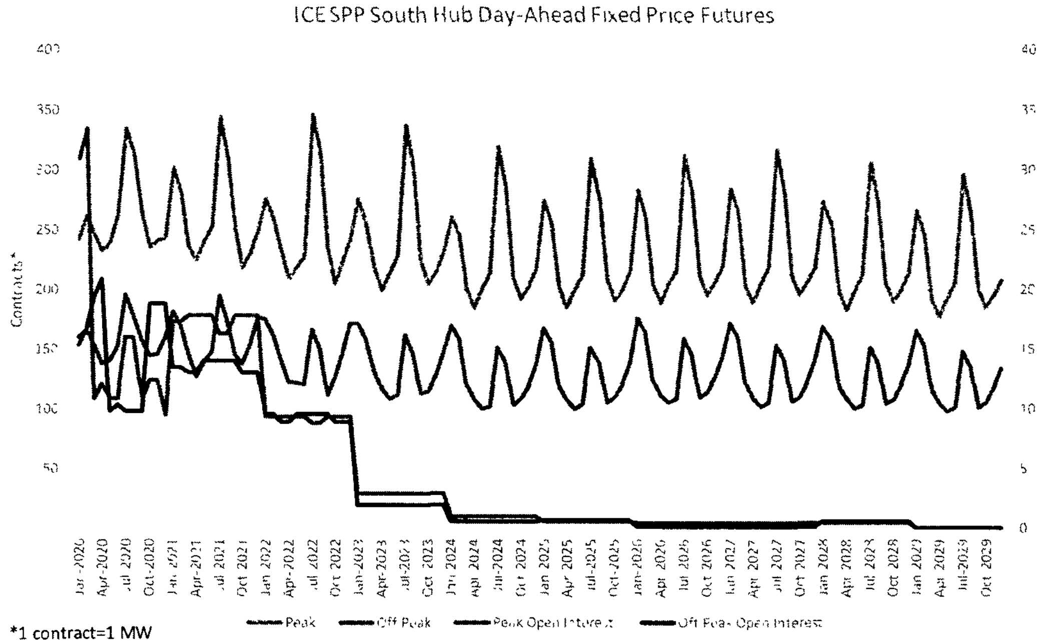
A. No. SWEPCO issued a request for proposal (RFP) that resulted in a 5-year purchase of physical gas from NextEra Energy Marketing delivered to Enable Gas Transmission. SWEPCO did not purchase NYMEX natural gas futures contracts at the Henry Hub. Pursuant to the agreement, and labeled as a "Special Condition," NextEra Energy Marketing retained the option of choosing any of three locations (including a "flex pool") to deliver this gas into the Enable Gas Transmission system for transportation by SWEPCO, which allows NextEra to source their gas from a broad range of resources. This delivery point optionality was specifically requested by NextEra Energy Marketing and likely reflects the extrinsic value of this option in their pricing. Mr. Griffey's analysis does not include this inherent value and does not support his inference that NYMEX natural gas futures can be relied upon after approximately two years (when open interest is low, or zero).

IV. INTERCONTINENTAL EXCHANGE POWER FUTURES CONTRACT PRICES ARE NOT A SUITABLE LONG-TERM FORECAST OF SPP POWER PRICES

Q. DO YOU AGREE WITH TIEC WITNESS GRIFFEY'S ASSERTION THAT INTERCONTINENTAL EXCHANGE POWER FUTURES CONTRACT PRICES SHOULD BE SUBSTITUTED FOR THE COMPANY'S FUNDAMENTALS FORECAST FOR EVALUATION OF THE SELECTED WIND FACILITIES?

A. No. Substitution of Intercontinental Exchange (ICE) SPP South Hub Day-Ahead Peak/Off Peak Fixed Price Futures contract prices for the Company's model-driven assessments of the balance of supply, demand and resulting power price has many of the same flaws discussed earlier about the NYMEX natural gas futures contract prices. Specifically; 1) ICE SPP South Hub power futures contract prices represent a different area than the Company's referenced SPP Central Zone; 2) ICE SPP South Hub power futures contract prices are functionally illiquid (i.e., not available) for quantities the size of the Selected Wind Facilities (1,485 MW) and there is zero open interest in many contract months, and; 3) the ICE SPP South Hub power futures contract is for only 1 MW, which represents a negligible amount of SPP power. In fact, the largest monthly open interest in both the on- and off-peak futures contracts (provided in the Company's response to TIEC RFI 10-1) beyond January 2020 is 284 MW, which is less than 20% of the nameplate capacity of the 1,485 MW Selected Wind Facilities. Figure 5 illustrates the ICE SPP South Hub On- and Off-Peak futures contract power prices and open interest for all contracts as of 1/14/2020.

Figure 5



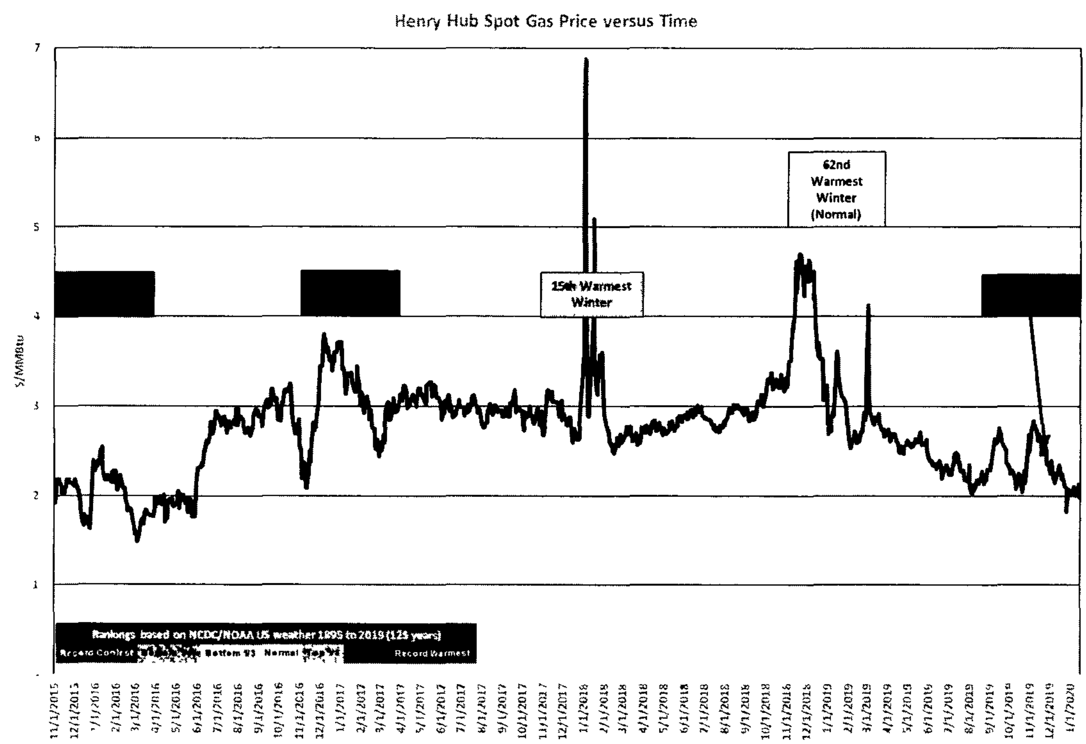
V. COMPARISON OF THE COMPANY'S NATURAL GAS PRICE FORECAST TO ACTUAL SPOT PRICES

Q. TIEC WITNESS POLLOCK COMPARED ACTUAL HENRY HUB NATURAL GAS SPOT PRICES TO THE COMPANY'S NATURAL GAS PRICE FORECAST TO SUPPORT HIS OPINIONS ABOUT THE ACCURACY OF THE COMPANY'S FORECASTS. WHAT DOES HE NEGLECT TO INCLUDE IN HIS ANALYSIS?

A. Mr. Pollock's comparison (Pollock Direct Testimony, page 16, lines 13-14, and page 17, lines 1-10) presents actual Henry Hub natural gas spot prices for the years 2015 – 2019 for comparison to the Company's weather-normalized natural gas price forecast. Figure 6 illustrates actual Henry Hub natural gas spot prices from the same period with annotation of weather rankings from the National Oceanic and Atmospheric Administration's (NOAA) climate database. Of the 125 years of record; the winters of

2015-16, 2016-17 and December of 2019 were top 10 warmest; the winter of 2017-18 was 15th warmest, and; the winter of 2018-19 was "normal." Not represented in Figure 6 are the prior five years, three of which experienced top 25% warmer-than-normal weather, with the winter of 2011-12 experiencing the second warmest winter in 125 years.

Figure 6



Mr. Pollock's Table 4 (Pollock Direct Testimony, page 17) of natural gas spot prices (2015/$2.63, 2016/$2.51, 2017/$2.98, 2018/$3.16 and Dec 2019/$2.56) reveals a link between low natural gas prices and near-record winter warmth. With the normal winter of 2018 (62nd of 125) presenting prices in November/December 2018 near $4.50/MMBtu and the near-record warm December of 2019 (6th of 125) presenting prices near $2.30/MMBtu, it highlights the deficiency of Mr. Pollock's comparison of the Company's weather-normalized forecast to actual Henry Hub spot gas prices. My Direct Testimony previously addressed the need to account for these weather impacts (Bletzacker Direct Testimony, page 6, lines 1-12).

Q. PLEASE EXPLAIN THE RELATIONSHIP BETWEEN WARM WINTERS AND LOW GAS PRICES.

A. Warmer-than-normal winter weather reduces natural gas demand, particularly for residential and commercial consumers and the non-process load of industrial consumers. While natural gas storage fields are designed to meet winter peak-day demand, when winter weather is warm and demand is lower, storage takes up the excess gas supply. Subsequently, warmer-than-normal winters result in less storage refill demand in the following summer with correspondingly discounted natural gas prices.

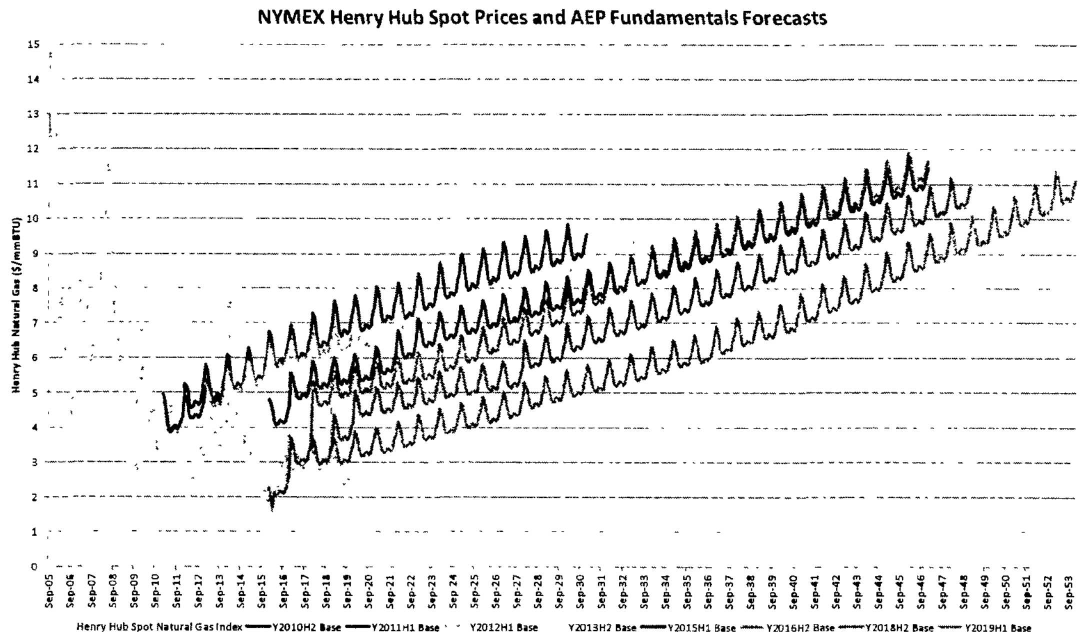
Q. PLEASE EXPLAIN WHAT IT MEANS THAT THE COMPANY'S GAS PRICE FORECASTS ARE WEATHER-NORMALIZED.

A. The Company's modeling is based upon the expectation that the consumption in each forecast-year is commensurate with 30-year average heating and cooling degree-days and the Company's gas price forecasts do not account for extended periods of abnormal weather. By contrast, Mr. Pollock's Henry Hub spot prices included periods of substantial variation from normal weather, as shown above.

Q. DO YOU AGREE WITH TIEC WITNESS GRIFFEY'S ASSERTIONS REGARDING THE COMPANY'S NATURAL GAS PRICE FORECAST; "LESSONS LEARNED," ACCURACY, AND COMPARISON TO ACTUAL HENRY HUB SPOT PRICES?

A. No. Regarding "lessons learned," Mr. Griffey asserts that the Company has not learned any lessons regarding natural gas price forecasting because no formal documents were produced (Griffey Direct Testimony, page 9, lines 18-21) and the Company's model-driven methodology has not changed (Griffey Direct Testimony, page 10, lines 1-3). The Company's modeled projections are based upon assumptions supported by the best available data at the time each forecast is created. "Lessons learned" are manifested in the revised assessments based on new data and are visible in each successive forecast. Figure 7 below illustrates that, as the natural gas industry's shale revolution progressed and Henry Hub spot prices continued to drop, so did the Company's natural gas price forecasts. As such, the Company's declining natural gas price forecasts are, in fact, documentation of "lessons learned." While no profound events (e.g., potential sea-change hydraulic fracturing regulations) are notable in the month-to-month escalation of the Company's forecasted natural gas prices within each forecast, the escalation of prices over time is consistent with others, including highly respected energy consultants, Energy Information Administration (EIA), SPP and others. The results of others' model-driven efforts are presented in Section VI below. The Company has continued its reliance on judicious, Aurora model-driven, fundamentals-based assessments based upon best-available information, as have numerous utilities, banks, utility regulators, energy consultants, and others. The Aurora model is routinely back-tested to benchmark its accuracy against history.

Figure 7



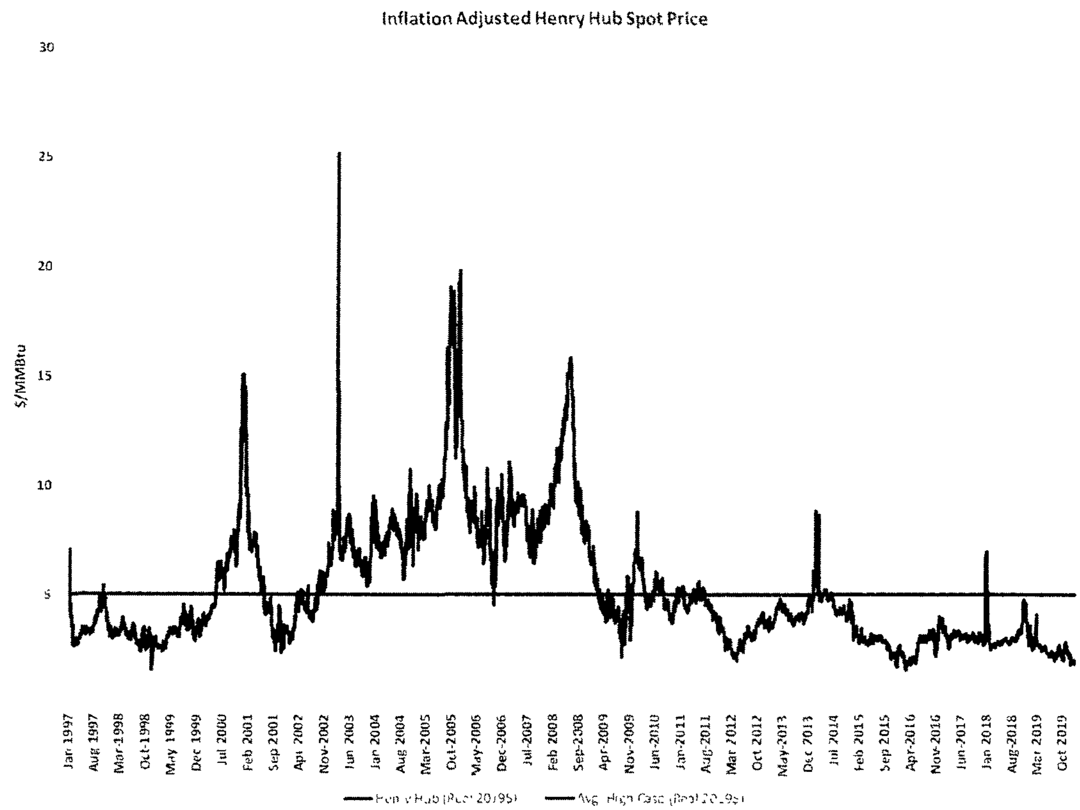
Regarding the Company's natural gas price forecast accuracy, Mr. Griffey compares the Company's natural gas price forecasts from 2010 to 2019 to Henry Hub spot prices and single-date NYMEX natural gas futures contract prices (Griffey Direct Testimony, page 21, lines 1-16). He describes the escalation rates of the Company's 2010 to 2018 natural gas price forecasts, calls out the 2019 natural gas price forecast as an "exception" as it "maintains escalation in excess of inflation throughout the period" and displays the escalation of the 12/30/2019 NYMEX natural gas futures contract for comparison. I illustrated, in Figure 2 above, that when inflation was removed from the NYMEX natural gas contract prices, an overall negative slope was revealed. This infers that, without the effects of inflation, prices would continue to drop from today's values until 2052. Consequently, Mr. Griffey's comparison is misleading.

Regarding the comparison of the Company's natural gas price forecasts to actual Henry Hub spot prices, Mr. Griffey implies that the gap between the Company's Base case natural gas price forecasts of Henry Hub spot prices and actual spot prices is avoidable (Griffey Direct Testimony, page 22 and page 23, lines 1-11). Mr. Griffey has not offered a Base case forecast, except for a trended set of NYMEX natural gas contract prices – the efficacy of which was discussed earlier and charted in Figure 4 herein.

Q. DO YOU AGREE WITH TIEC WITNESS POLLOCK'S DISMISSAL OF THE COMPANY'S HIGH GAS CASE AS "NOT REMOTELY PLAUSIBLE"?

A. No. Mr. Pollock's statement that "SWEPCO's High Gas scenario is not remotely plausible" (Pollock Direct Testimony, page 8, lines 11-12) is oblivious to the volatility and magnitude of past natural gas spot prices. Figure 8 below compares inflation-adjusted actual daily Henry Hub spot prices from 1997-2020 to the inflation-adjusted Henry Hub average spot price ($5.06/MMBtu) from the Company's High Gas forecast. The actual daily Henry Hub spot price average for this period was $5.24/MMBtu, which is $0.18 higher than the Company's High Gas forecast average. Mr. Pollock's portrayal of the Company's High Gas forecast as "not remotely plausible" is detached from past evidence, lacks consideration of inherent volatility due to weather or force majeure events, and does not give credence to the possibility of any sea-change regulatory, geopolitical or other influences.

Figure 8



VI. COMPARISON OF THE COMPANY'S NATURAL GAS PRICE FORECAST TO THIRD-PARTY FORECASTS

Q. ON PAGE 18 OF HIS DIRECT TESTIMONY, TIEC WITNESS GRIFFEY STATES THAT SOUTHWESTERN PUBLIC SERVICE COMPANY (SPS) USES A "LONG-TERM TRENDED FORECAST OFF OF THE NYMEX MARKET PRICE." DO YOU HAVE A COMMENT?

A. Yes. It is my understanding that SPS uses a blending of NYMEX futures prices and three fundamentals-based forecasts from respected, industry leading sources, to forecast monthly Henry Hub gas prices. These long-term fundamentals-based forecasts are from Wood Mackenzie, IHS Energy, and Petroleum Industry Research Associates

(PIRA). The table below illustrates the method used by SPS in its Docket No. 46936 wind acquisition proceeding:

Natural Gas Forecast Weightings

Years	NYMEX	IHS Energy*	PIRA	Wood Mackenzie
2016-2019	100.0%	0.0%	0.0%	0.0%
2020	74.5%	8.5%	8.5%	8.5%
2021	49.7%	16.8%	16.8%	16.8%
2022 to end of forecast period	25.0%	25.0%	25.0%	25.0%

*formerly known as CERA or Global Insight

Consistent with my rebuttal testimony above, I do not support the use of NYMEX futures prices as a substitute for a fundamentals based forecast, particularly in the years where there is little to no open interest reflected in the NYMEX futures prices. However, in HS Figure 9 below, I have used the method illustrated in the above table and produced a forecast with recent information from NYMEX, IHS Energy, PIRA, and Wood Mackenzie. Highly Sensitive Figure 9 demonstrates that the blended forecasting method employed by SPS in Docket No. 46936 results in a forecast that is above the break-even price for the Selected Wind Facilities in every year but the first few when the NYMEX futures prices are weighted more heavily than the fundamentals based forecasts. It is also evident that trended NYMEX futures prices are a significant outlier and, if removed from the SPS blending method, an even greater gap above the break-even price for the Selected Wind Facilities would emerge.

Highly Sensitive Figure 9

[redacted]

Q. TIEC WITNESS GRIFFEY PRESENTED TWO THIRD-PARTY NATURAL GAS PRICE FORECASTS TO ASSERT HIS CLAIM THAT THE COMPANY'S NATURAL GAS PRICE FORECAST IS TOO HIGH. DO YOU AGREE WITH HIS APPROACH AND ASSERTION?

A. No. Every natural gas price forecast in the Company's possession since 2018 that was delivered to TIEC witness Griffey through the discovery process along with the EIA AEO 2020 and a comparison to SWEPCO's Break-Even natural gas price is illustrated in Highly Sensitive Figure 10 below. This includes IHS (formerly CERA), Platt's Analytics (formerly PIRA), EIA, SPP and others. The SWEPCO break-even natural gas prices linked to the SWEPCO Break-Even SPP electric power prices from the Company's direct testimony are also shown. These aggregated benchmark forecasts provide the full picture not provided by Mr. Griffey (Griffey Direct Testimony, page 30, lines 1-8 and figure 7). The full picture reveals a strong consensus near the middle of the range of forecasts that does not support Mr. Griffey's assertion. It also shows that the proposed project's break-even is close to the bottom of all forecasts.

Highly Sensitive Figure 10

[redacted]

Q. IN YOUR EXPERIENCE, DO OTHER REPUTABLE FORECASTS SUCH AS IHS/CERA, PLATT'S ANALYTICS/PIRA, EIA, SPP AND THE INTERNATIONAL

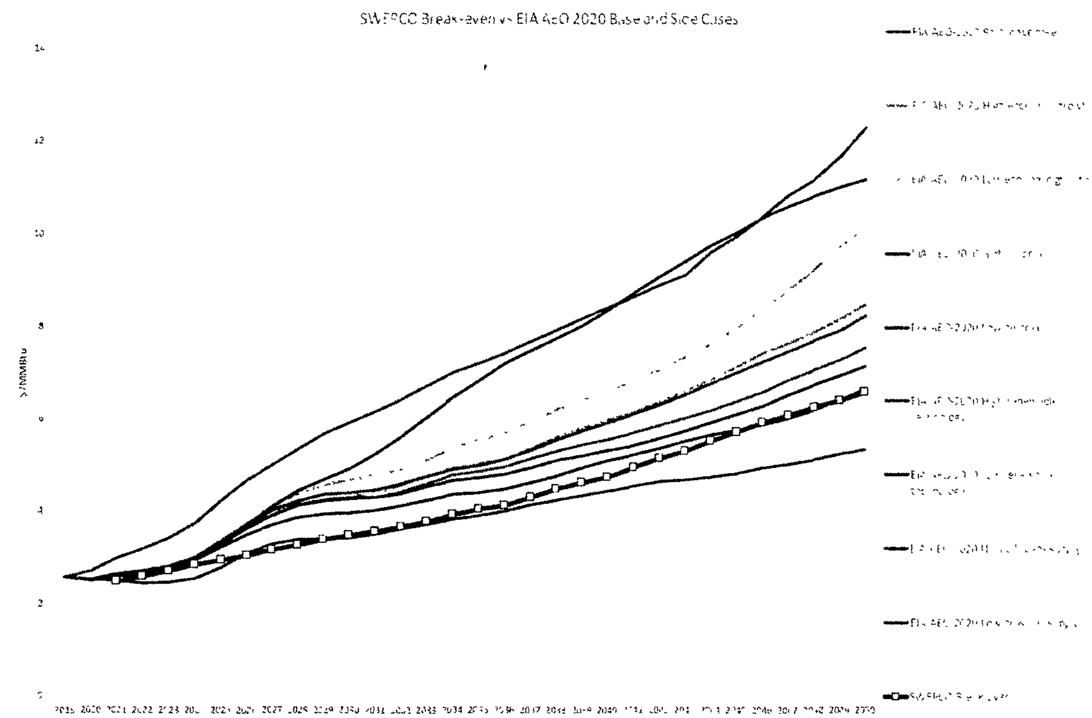
ENERGY AGENCY RELY ON NYMEX NATURAL GAS FUTURES CONTRACT PRICES AS ADVOCATED BY TIEC WITNESSES GRIFFEY AND POLLOCK AND OPUC WITNESS NALEPA?

A. No, with one exception. The exception is the IHS NYMEX Gas Scenario-7/2019, shown in Figure 8 as the blue line that tracks the Company's break-even price until approximately 2036 then trends slightly below the break-even. However, IHS discussed that scenario as follows: *"NYMEX futures prices are used to price financial contracts and are not a forecast of future spot prices. NYMEX futures prices represent the market consensus of the price to be paid now for delivery in the future and are a function of today's prices, the cost of natural gas storage, the risk-free cost of debt, and a return to the investor to compensate it for expected future price volatility."* Other than this one scenario that IHS disclaimed, none of the forecasts shown in Figure 8 used NYMEX futures in their forecast.

Q. DO YOU AGREE WITH TIEC WITNESS POLLOCK'S ASSERTION THAT, IN LIEU OF NYMEX NATURAL GAS FUTURES PRICES, THE COMMISSION COULD USE THE EIA AEO 2020 HIGH OIL AND GAS SUPPLY SIDE CASE FOR EVALUATING SWEPCO'S PROPOSED PROJECT?

A. No. EIA's AEO 2020 Reference Case and seven other side cases are above the break-even price for the Selected Wind Facilities, but Mr. Pollock chooses to highlight the High Oil and Gas Supply side case, which is EIA's lowest side case. Figure 11 below shows the range of EIA's AEO 2020 forecast cases relative to the break-even price for the proposed facilities.

Figure 11



Mr. Pollock's assertion that the Commission should use the EIA High Gas and Oil Supply side case (Pollock Direct Testimony, page 4, lines 23-24, Page 18, lines 16-19 and page 19, lines 1-9) does not address EIA's rationale for the creation of a range of side cases, and the embedded assumptions of the AEO 2020 High Oil and Gas Supply side case. Regarding the general rationale for AEO 2020 side case creation, EIA states: *"Factors such as economic growth, future oil prices, the ultimate size of domestic energy resources, and technological change are often uncertain. To illustrate some of these uncertainties, EIA runs side cases to show how the model responds to changes in key input variables compared with the Reference case."* Regarding the embedded assumptions of the AEO 2020 High Oil and Gas Supply side case, EIA warns: *"Projections of tight oil and shale gas production are uncertain because large portions of known formations have relatively little or no production history and extraction technologies and practices continue to evolve rapidly. In the High Oil and Gas Supply case, lower production costs and higher resource availability allow higher production at lower prices."* To provide a balance, EIA also provides a Low Oil and Gas Supply side case and states: *"In the Low Oil and Gas Supply case, EIA applied assumptions of lower resources and higher production costs."* Mr. Pollock acknowledges that EIA's High Oil and Gas Supply case provides the lowest of EIA's projected natural gas prices (Pollock Direct Testimony, page 19, lines 9-12) and advocates its use in this proceeding without providing complete context or even discussing EIA's other side cases.

Q. ARE THERE INDICATIONS IN THE NATURAL GAS MARKET THAT A "HIGH OIL AND GAS SUPPLY" SCENARIO IS NOT SUITABLE AT THIS TIME?

A. Yes. Leading shale-focused companies are addressing the adversity of currently low prices by informing investors that capital investment is reaching a limit. Namely:

Chesapeake Energy Corporation (10-Q, 11/5/2019, page 64)

> *"If depressed prices persist or decline throughout 2020, our ability to comply with the leverage ratio covenant under our revolving credit facility during the next 12 months will be adversely affected and may cause doubt about our ability to continue as a going concern."*

Southwestern Energy CEO William Way (3Q2019 earnings call)

> *"The company may halt all drilling when it looks at commodity futures prices in 2020...when the price of the commodities reaches a point where we cannot meet the company's rigorous economic threshold, we will reduce or stop activity."*

Apache CEO John Christmann (3Q2019 earnings call)

> *"Investors are frustrated with excessive capital investment by U.S. producers in pursuit of growth, which has come at the expense of both return on and return of capital. For these and other reasons, the broad energy sector is out of favor, and there is very little investor interest in publicly traded E&P companies"*

Additionally, as reported by S&P Global Market Intelligence (2/5/2020); *"S&P Global Ratings cut the credit ratings of six pure-play shale gas producers on February 3, based on worries that they will not be able to refinance billions of dollars in bonds because of expected low gas prices and chronic overspending to drill for gas the market doesn't want."* The credit rating downgrades affected EQT Corp., Range Resources Corp., Antero Resources Corp., Ascent Resources Utica Holdings LLC, CNX Resources and Gulfport Energy Corp. Natural gas and oil exploration companies must always maintain capital discipline, focus on productivity improvements and apply new technology. However, the sentiments expressed above infer a potential reduction of natural gas supply until prices can support their credit metrics and justify further shale development.

VII. CONSIDERATION OF POTENTIAL CARBON MITIGATION IN THE COMPANY'S FORECAST IS REASONABLE

Q. DO YOU AGREE WITH TIEC WITNESS POLLOCK'S CLAIM THAT IT IS INAPPROPRIATE FOR THE COMPANY TO PROJECT A CARBON BURDEN AT THIS TIME?

A. No. The Company's Base Case carbon price proxy is intended to reflect the risks and costs associated with the regulation of carbon dioxide emissions from fossil fuel-fired power plants. The United States Environmental Protection Agency (EPA) has determined carbon dioxide to be a pollutant under the Clean Air Act which makes CO_2 emissions subject to further limitation. To this point, President Obama's Clean Power Plan was issued and subsequently replaced by President Trump's Affordable Clean Energy Rule. This January, House Democrats proposed an economy-wide plan for achieving net-zero carbon emissions, including the power industry, labeled the CLEAN Future Act. It is proposed to be implemented through a national credit trading system that is weighted to burden coal- and gas-fired generators. This stark partisan contrast highlights the potential for change regarding the implementation of carbon emission regulations and the need to account for the possibility of carbon emission costs in the future. The study period employed by the Company for the Selected Wind Facilities extends 30 years into the future. As such, the carbon price proxy used for fundamentals forecasting is a reasonable assessment of future costs based on the status for carbon regulations and potential changes thereto. The risk of the power industry incurring carbon emission costs in the future <u>is not zero</u> and eliminating all potential carbon price impacts from the forecast, as suggested by Mr. Pollock (Pollock Direct Testimony, page 27, lines 17-20), would not realistically reflect the potential future impact of carbon emission limitations.

Q. ARE OTHER UTILITIES AND COMPANIES ASSIGNING A PRICE ON CARBON FOR INTERNAL BUSINESS PLANNING PURPOSES?

A. Yes. In a 2017 report issued by CDP Global, an international non-profit organization that gathers environmental disclosures from companies and organizations around the world, it was reported that 84% of the Utilities Sector was assigning a price on carbon for internal business planning purposes. In the 2019 disclosures gathered by CDP, many of the TIEC members participating in this proceeding indicated that they also assign a price on carbon for internal business planning purposes, including Air Liquide, Eastman Chemical, Komatsu, and Occidental Petroleum.

VIII. THE APPLICABILITY OF NYMEX FUTURES CONTRACT VOLATILITY CALCULATIONS TO THE COMPANY'S NATURAL GAS PRICE FORECAST IS NOT COMPELLING

Q. ARE THE COMPANY'S HIGH, LOW, AND LOW NO CARBON CASES INTENDED TO CAPTURE THE WIDE RANGE OF PROBABILITY DISTRIBUTION PROFFERED BY TIEC WITNESS GRIFFEY (GRIFFEY DIRECT TESTIMONY, PAGE 27, LINES 4-14 AND PAGES 28-29)? IF NOT, WHY?

A. No. The Company's High, Low, Base No Carbon and Low No Carbon cases are wholly stand-alone scenarios that accommodate certain assumptions not contained in the Base Case. They are not surrogates for calculations of the implied volatility of NYMEX natural gas futures contracts as Mr. Griffey proposes. The purpose of these cases is to provide a plausible range of outcomes with meaningful and straightforward assumptions. The High and Low cases consider higher and lower North American demand for electric generation and, consequently, higher and lower fossil fuels prices, respectively. The exclusion of carbon mitigation modeling from the Base and Low No Carbon cases was intended to thoroughly display the effect of the carbon proxy.

Q. IN YOUR EXPERIENCE, DO OTHER REPUTABLE FORECASTS SUCH AS IHS/CERA, PLATT'S ANALYTICS/PIRA, EIA, SPP AND THE INTERNATIONAL ENERGY AGENCY RELY ON CALCULATIONS OF THE IMPLIED

VOLATILITY OF NYMEX NATURAL GAS FUTURES CONTRACTS AS ADVOCATED BY TIEC WITNESS GRIFFEY?

A. No. I have not seen forecasts by these entities that rely on the implied volatility of NYMEX natural gas futures as Mr. Griffey proposes.

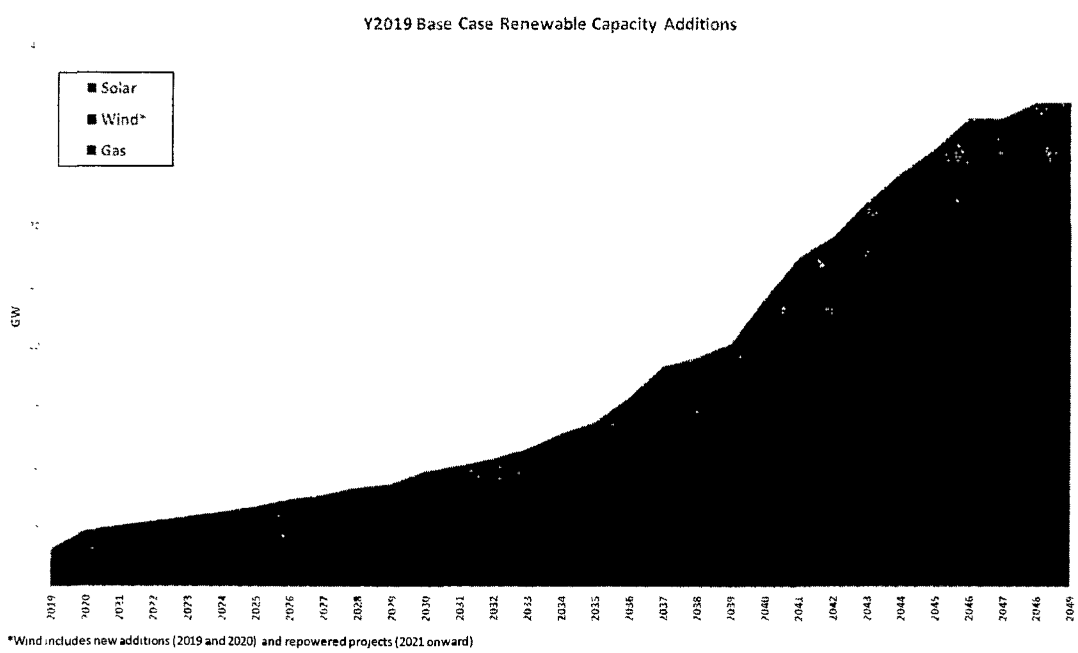
IX. NATURAL GAS IMPLIED HEAT RATES DO NOT IMPLY THE COMPANY HAS OVERSTATED SPP POWER PRICES

Q. DO YOU AGREE WITH TIEC WITNESSES GRIFFEY AND POLLOCK'S CLAIM THAT THE COMPANY OVERSTATES SPP POWER PRICES AS EVIDENCED BY NATURAL GAS IMPLIED HEAT RATE PROJECTIONS?

A. No. Natural gas implied heat rates (MMBtu/MWh) are simply the Aurora model-derived SPP power prices ($/MWh) divided by the model's SPP zone natural gas prices ($/MMBtu). The Company does not assume natural gas implied heat rates as put forward by Mr. Griffey (Griffey Direct Testimony, page 35, lines 8-18) and Mr. Pollock (Pollock Direct Testimony, page 4, lines 4-12); rather, they are a discreet result of Aurora's capacity expansion modeling. Wind resources that create value on a going-forward basis are constructed, while those that have no value on a going-forward basis are retired. Both Mr. Griffey's observation that the Company's modeling did not add any additional wind resources and Mr. Pollock's assertion "that the amount of additional renewable energy resources is understated" (Pollock Direct Testimony, page 28, line 19) after 2020 are incorrect. Existing wind resources can be retired after their life expectancy, however, re-powering of the wind resources in situ (at a lower cost than a new facility) is the outcome indicated by the Company's modeling (see Figure

12 below). Wind resources in excess of those that were re-powered did not create value on a going-forward basis and were not constructed by the Aurora model. This does not implicate the Company's SPP power price forecast as suggested by Mr. Griffey (Griffey Direct Testimony, page 5, lines 17-21). It is a judicious, economics based model-derived outcome that demonstrates; 1) the Company doesn't ignore improved technology risk, and; 2) there are no "problems with SWEPCO's projections of power prices [that] can be seen in the implied market heat rates" (Griffey Direct Testimony, page 33, lines 18-21 and page 34, lines 1-2).

Figure 12



X. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

SOAH DOCKET NO. 473-19-6862

PUC DOCKET NO. 49737

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

REBUTTAL TESTIMONY OF

KAMRAN ALI

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

FEBRUARY 12, 2020

TESTIMONY INDEX

EXHIBITS

EXHIBITS	DESCRIPTION
EXHIBIT KA-1R	DISIS STUDIES FOR SELECTED WIND FACILITIES

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Kamran Ali. American Electric Power Service Corporation (AEPSC), one of several subsidiaries of American Electric Power Company, Inc. (AEP), employs me. I am currently Managing Director of Transmission Planning for AEPSC. My business address is 8500 Smiths Mill Road, New Albany, OH 43054.

Q. ARE YOU THE SAME KAMRAN ALI WHO FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address some of the issues raised in the direct testimony of ETEC-NTEC witness John W. Chiles. Specifically, my rebuttal:

1. Clarifies that the Selected Wind Facilities were evaluated through SPP's Definitive Interconnection System Impact Study (DISIS) process, which includes the steady state thermal and voltage analysis, stability and short-circuit analysis that Mr. Chiles asserts was not done.
2. Clarifies the Company's generation dispatch assumptions and explains why the generation-to-generation transfer methodology employed by the Company for First Contingency Incremental Transfer Capability (FCITC) analysis is a reasonable approach.
3. Further explains the reasonableness of the Company's Gen-Tie analysis for mitigating potential future congestion if it develops for the Selected Wind Facilities.

III. RESPONSE TO MR. CHILES

Q. MR. CHILES CLAIMS (PAGE 6) THAT THE COMPANY HAS FAILED TO DEMONSTRATE THAT THE SELECTED WIND FACILITIES DO NOT NEGATIVELY IMPACT SYSTEM VOLTAGE OR SYSTEM STABILITY AND THAT THE COSTS OF ANY MITIGATION PLANS NEEDED TO ADDRESS VOLTAGE OR STABILITY ISSUES ARE BEING WITHHELD FROM THE COMMISSION. DO YOU AGREE?

A. No. The SPP has already analyzed the voltage and stability issues raised by Mr. Chiles and the associated costs are included in the Company's analysis. An interconnection customer seeking to interconnect its generating facility to the Southwest Power Pool (SPP) transmission system is required to go through SPP's Generator Interconnection (GI) Study Process. SPP's GI Study Process includes a mandatory Definitive Interconnection System Impact Study (DISIS)[1], which consists of steady-state thermal and voltage analysis, transient and dynamic stability, and short circuit analysis. The primary objective of the DISIS is to identify the system constraints, transient instabilities, and over-dutied equipment associated with connecting the generation to the transmission system. SPP provides a report that identifies all the transmission network constraints resulting from its analysis and the upgrades required to address those constraints. Southwestern Electric Power Company's (SWEPCO's) response to data request ETEC-NTEC 2-20 included links to SPP's DISIS reports for the clusters that include the Selected Wind Facilities and these reports are provided in EXHIBIT

[1] DISIS is an engineering study that evaluates the impacts of the proposed interconnection on the reliability of the transmission system.

KA-1R. SPP's GI Study process also assesses any necessary transmission upgrade costs, which are directly assigned to the generation interconnection customer.

In accordance with the Eligibility and Threshold requirement in Section 5.3 of the Request for Proposals (RFP), the projects bidding into the RFP had to have a completed SPP System Impact Study to qualify for further evaluation by the Company. As a result, the Selected Wind Facilities were evaluated through SPP's DISIS process and the transmission upgrade costs identified by SPP for those Facilities were embedded within their purchase prices. The Company did not need to replicate the analyses already performed by SPP to determine impacts of the Selected Wind Facilities on SPP's transmission system.

Q. DO YOU AGREE WITH WITNESS CHILES' INTERPRETATION OF THE DIFFERENCES BETWEEN ERIS AND NRIS (P. 7)?

A. No, I do not. The two GI products currently offered by SPP to interconnection customers are Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS)[2]. Although Mr. Chiles characterizes the difference between them as non-firm vs. firm service, that is not the case. Generators requesting ERIS are eligible to deliver their electric output across the transmission system using the existing firm or non-firm capacity of the system on an as available basis. NRIS allows generators to integrate with the transmission system in a manner comparable to how transmission owners *historically* integrated generating facilities to serve native load customers as a Network Resource. NRIS studies are likely to result in more

[2] At the time the Interconnection Request is submitted to SPP, an interconnection customer must request either ERIS or NRIS.

directly assigned network upgrade costs given that these studies involve more stringent system impact limits for the purpose of identifying needed network upgrades as compared to ERIS studies. However, the additional potential transmission investment associated with NRIS status does not protect against future curtailments of the generation facilities nor does it guarantee firm delivery of the full generator output. Upon interconnection, both NRIS and ERIS resources have access to the SPP integrated marketplace although neither ERIS nor NRIS translates to firm transmission service. Currently, entities are required to go through SPP's long-term transmission service study process,[3] utilizing different study models and assumptions, to attain firm transmission service.

The costs assessed and the value attained for ERIS, NRIS and long-term transmission service are currently being discussed in SPP stakeholder forums for potential modification. As a result, and because there are no delivery benefits, NRIS was not pursued for the Selected Wind Facilities. The Company's use of the ERIS power flow model, which included SPP identified system upgrades for ERIS interconnection, is appropriate for performing deliverability assessments.

Q. HAS THE COMPANY RECENTLY REQUESTED FIRM TRANSMISSION SERVICE FOR THE PROPOSED FACILITIES?

A. Yes. As discussed more fully in the rebuttal testimonies of Company witnesses Richard Ross and Johannes Pfeifenberger, the Company has requested firm long-term transmission service for the proposed facilities. After the Company receives the study

[3] The long-term transmission service study process determines capacity deliverability in SPP by evaluating specific source-to-sink transfers.

results from the SPP, it will evaluate whether the benefits of such service exceed the cost of any additional transmission upgrades required to obtain such service.

Q. DO YOU AGREE WITH MR. CHILES' ASSESSMENT OF SPP'S METHODOLOGY FOR IDENTIFYING UPGRADES FOR ERIS (PAGE 8)?

A. No. ETEC-NTEC witness Chiles believes (Page 8) that SPP identified upgrades for ERIS by modeling the wind generation at only 20% of nameplate capacity. However, SPP's steady state and stability studies performed for ERIS to identify necessary transmission upgrades are designed to allow full output of the proposed generating facility. Specifically, SPP clusters interconnection requests into regional groupings and the Variable Energy Resources (VER) (which includes wind resources) in each group are dispatched at 100% nameplate generation while the VERs in the remote areas are dispatched at 20% nameplate in the summer peak cases. These projects are dispatched across the SPP footprint using load factor ratios.

The Company performed FCITC analysis, in addition to its reliance on the SPP GI study, with the intention of identifying any local deliverability issues that will result in curtailment during real time operations. In essence, the amount of proposed wind generation in SPP's GI queue far exceeds the current and forecasted peak demand. SPP's analysis methodology is designed to assess the transmission capability to facilitate integration of a cluster of resources under a potential scenario that all of them may be operating at 100% but generators outside the study cluster are scaled down to balance demand and generation. As a result, congestion and curtailment may become an issue in real-time operation when generators that rely on same transmission capacity but are part of different clusters are dispatched. The Company's FCITC analysis quantified and measured the risk of congestion and curtailment under such credible scenarios and eliminated clusters that have no or limited transmission deliverability under these scenarios.

Q. MR. CHILES (PAGE 8) NOTES CONCERNS WITH THE GENERATION DISPATCH ASSUMPTIONS IN EACH CLUSTER AND THE IMPACTS OF THESE ASSUMPTIONS ON COMPANY'S FCITC ANALYSIS. DO YOU WISH TO ADDRESS THESE CONCERNS?

A. Yes. While SPP's analysis is a robust methodology for the determination of ERIS network upgrades to interconnect a generator, the purpose of the Company's FCITC analysis was different and designed to determine which projects have a high risk of congestion and curtailment when the output from generators in clusters is delivered, specifically, to the AEP Zone in SPP. As described in my direct testimony, the approach utilized by the Company to meet this objective was to perform an FCITC analysis utilizing the four clusters that were determined based on dependence of generators on similar transmission lines. In this method, the wind output of the cluster under study was increased from 20% of nameplate capacity while the generation resources in the AEP Zone were proportionally scaled down (referred to in my testimony as the generation-to-generation transfer methodology).

Witness Chiles states that the change made by the Company was to increase all wind generation in the cluster to 100%. To clarify, the wind generation in each cluster was modeled at 20% in the base model and transfers were simulated above the cluster's resources' initial dispatch by increasing the wind generation and uniformly scaling the generating resources in the AEP Zone. Transfers were incrementally increased from

20% until transmission facilities reached their thermal limits. Clusters with no or limited transmission capacity under these scenarios were barely able to accommodate wind dispatch above the 20% nameplate. This poses a significant risk to our customers considering the transmission capacity is limited and more renewable generation in these regions may further increase the risk of curtailment. ETEC-NTEC Witness Chiles' conclusion that the Company's screening analysis of RFP bids is flawed due to assumptions regarding the base modeling of existing wind capacity, therefore, is not accurate.

Q. ON PAGE 9, MR. CHILES EXPRESSES CONCERNS REGARDING PRO-RATA DECREMENTING OF GENERATION IN THE AEP ZONE IN SPP. DO YOU AGREE?

A. No. The Company's FCITC analysis, using the generation-to-generation transfer methodology, is a standard industry practice routinely employed by regional transmission organizations and independent system operators to stress the transmission system with the objective of identifying transmission system weaknesses. As also previously stated, the intent of the Company's deliverability analysis was to identify the clusters that are likely to be least constrained when delivering power from generators in those clusters to customers in the AEP Zone. The generation-to-generation transfer simulations adequately quantify the transmission capability "head room," which is a measure of the robustness of the transmission system between the wind clusters and the AEP zone. Ultimately, the Company selected wind projects in the clusters that were determined to be most deliverable following FCITC analysis, maximizing the probability of delivering the wind power to customers in the AEP Zone even if additional wind develops in those clusters.

Furthermore, SPP performs its transmission service studies using a similar methodology. Transmission service requests are modeled as generation-to-generation transfers, which are accomplished by dispatching the request source and re-dispatching the request sink.

Mr. Chiles also claims that the most accurate representation for the FCITC analysis would have been to decrement only the generation that would be displaced by the proposed projects. However, in SPP's marketplace, generators are dispatched using an economic merit order, i.e., dispatching the lowest-cost generation to meet the region's electricity demand taking into account the various day-ahead and real-time constraints of the SPP transmission system. At any given time, dispatch of the Public Service Company of Oklahoma (PSO) and SWEPCO generators in real-time markets will depend on the system demand, relative cost of operating these generators, and constraints on the SPP transmission system. The Company, therefore, cannot accurately forecast which generators will be displaced by the proposed projects under the SPP integrated marketplace construct and for that reason; a consistent approach of pro-rata decrementing of generators in the AEP Zone is rational.

Q. MR. CHILES STATES (PAGE 13) THAT THE COMPANY SHOULD RERUN ITS ENTIRE ANALYSIS ASSUMING THE GEN-TIE IS NEEDED. IS THIS A REASONABLE REQUEST?

A. No. In fact, as Mr. Chiles recognizes (Page 13), the Company is not seeking approval of a gen-tie in this case. The fact that Company analyzed a gen-tie does not suggest that it is likely. Instead, the gen-tie scenario provides the Commission a view of the benefits of the Selected Wind Facilities under a scenario where significant congestion materializes ***and*** SPP's integrated transmission planning process fails to produce a more economical solution for SWEPCO customers. The gen-tie scenario adds nearly $500 million of additional capital costs to the project evaluation and represents a conservative view. As stated in my direct testimony and in response to discovery,[4] should congestion or curtailments materialize at a significant level; the Company will evaluate all potential transmission solutions, including those identified through an SPP integrated transmission planning process, to ensure the most economical solution is pursued.

Q. MR. CHILES HAS STATED THAT A TRANSIENT STABILITY ANALYSIS MAY IMPACT THE GEN-TIE EVALUATION (PAGE 14). DO YOU WISH TO ADDRESS HIS CONCERN?

A. Yes. As previously stated, the Selected Wind Facilities were evaluated through SPP's DISIS process, which includes a transient stability analysis. To reiterate, the Company is not seeking approval of a gen-tie in this proceeding. However, if the Company determines that a gen-tie is warranted in the future, the Company will submit a new generation interconnection project to SPP for the gen-tie interconnection location near Tulsa. SPP will perform relevant assessments including stability analysis for this new interconnection location.

---

[4] ETEC-NTEC 2-10